Section A
Northwest Power Planning Council - *Study of Western Power Market Prices, Summer 2000, Executive Summary*

This section reprints the executive summary of the Northwest Power Planning Council's (NWPPC) Study of Western Power Market Prices Summer 2000, released in October 2000[1]. Washington utilities operate as part of a west-wide transmission and power supply system. Any understanding of the electricity supply and price issues faced by Washington utilities must be within the context of the western U.S. power market. This report provides that context. It also provides the Council's recommendations for how to mitigate the extreme price volatility that has characterized western power markets in 2000.

Introduction

Almost two years ago, the NWPPC initiated a study of the adequacy of the Northwest's power supply. This study was motivated by the observation that while the region had enjoyed several years of robust economic growth and, consequently growth in the demand for electricity, there had been very little in the way of new generation development. At the same time, efforts to improve the efficiency of electricity use in the region had been reduced dramatically because of the uncertainty of utility restructuring. This raised the concern that under conditions of high stress, the system might not be able to fully meet the region's power needs to serve load and to maintain the reserves essential to a reliable system. Conditions of high stress involve combinations of high weather-driven loads, poor hydropower conditions, and forced outages of thermal and hydropower generating units. The study was completed late last winter.[2] It concluded that:

- There is an increasing possibility of power supply problems over each of the next few winters (December, January, and February), reaching a probability of 24% by 2003. This takes into account both regional resources and the availability of imports. The level and duration of the possible shortfalls could be relatively small – a few hundred megawatts (MW) for a few hours – or quite large – a few thousand MW for extended periods.
- The region would need the *equivalent* of 3,000 MW of new capacity to reduce the probability to a more acceptable 5% level. That new capacity should take the form of new generation ***and*** economic load management, i.e., reductions or shifts in consumer loads that make economic sense for the consumer and the power system.
- It was unlikely that market prices would be sufficient to stimulate the development of sufficient new generation in that time frame. This meant that in the near-term, an even higher priority needed to be placed on developing economic load management opportunities.

While this study generated a good deal of interest, it has been difficult for people to get too concerned about probabilities generated by arcane computer models. This summer, however, developments in the power system have captured the attention of the industry and the public. Those developments resulted in unprecedented high prices in Western power markets, including the Northwest. Average prices for power traded for the heavy load hours of June 28th at the Mid-Columbia trading hub reached almost $700 per megawatt-hour (MWhr). This is more than 10 times the previous high and is consistent with the prices seen at other trading hubs in the West. Moreover, even for off-peak periods and days for which prices were not at extreme levels, they were considerably higher than past summers.

These prices have caused some economic hardship in the Northwest. The hardships have been limited by the fact that spot market purchases represent a small portion of the total amount of power consumed in Northwest. Relatively few retail customers purchase directly from the market or are on market-indexed rates. However, several industrial customers who are on such rates found it uneconomical to continue operation at these power rates. In addition, several utilities are seeking increases in their retail rates to cover the increased cost of power purchases. Because of these impacts, Governors Locke of Washington and Racicot of Montana asked the NWPPC to undertake a study to explain the reasons for the prices seen on the market and the actions that might be taken to mitigate these prices.

The NWPPC believes that the market prices seen this summer are a tangible manifestation of the fundamental problems identified in the NWPPC's power supply adequacy study of last winter. That is, the prices are an indicator of approaching scarcity. This summer, the system, which already is facing tight supplies, has been further stressed by combinations of unusually high loads, poor hydropower conditions, and forced outages of thermal units. There is little in the way of price-responsiveness in demand to mitigate these prices. Those who had available supply were able to ask for and receive high prices. This combination of factors is precisely what leads to the power supply adequacy problems identified in the NWPPC's earlier study. These factors apply not only to the Northwest but also to the entire Western Interconnected System. There were some additional factors acting this summer related to the design of the California market, but they should not obscure the basic underlying problem. Absent some action, the next similar event could result in not only high prices but also a failure of the system to meet loads.

In the following paragraphs we will summarize the evidence regarding the factors affecting Western market prices this summer, focusing in some detail on the last week in June, the period in which the highest prices were observed. We will then offer some recommendations for actions to mitigate future price excursions and potential power supply adequacy problems.

What Caused this Summer's Prices?

As noted above, we believe the prices experienced this summer are symptomatic of an overall tightening of supply, exacerbated by a number of factors. Some of these factors are physical and economic, others are related to the relative immaturity of the competitive electricity market and the uncertainties involved in the transition from a regulated structure. The physical and economic factors include:

- unusually high weather-driven demands throughout the West,
- an unusual pattern of hydropower generation,
- a high level of planned and forced outages of thermal generating units, and
- high gas prices.

The factors related to market immaturity and transitional uncertainties include:

- the lack of a demand-side price response in the market;
- inadequate utilization of risk mitigation strategies, and
- factors related to the design and operation of the California market.

Overall Tightening of Supplies

Between 1995 and 1999, WSCC peak loads increased by nearly 12,000 MW, or by about 10%. The increase would have been even more if 1999 hadn’t been a relatively mild weather year. Generating capacity available during peak load months did not increase to keep pace with peak load growth. While peak loads increased by 12,000 MW from 1995 to 1999, generating capacity only increased by 4,600 MW.

We also believe that efforts to improve the efficiency of electricity use, i.e., conservation, have fallen off considerably in recent years. This is largely the result of the uncertainty created by the restructuring of the electricity industry. Utilities, who were the primary vehicle for conservation development, generally reduced their efforts because of concerns about creating potentially stranded investment if retail access resulted in the loss of customers. There were also concerns about the need to raise rates to cover conservation costs and the revenues lost as a result of conservation.

The effect of growth in demand outstripping the growth in resources is a narrowing of reserve margins. This implies more efficient utilization of existing capacity and was an anticipated benefit of moving to a competitive generation market. However, when it proceeds to the point of putting reliability at risk and destabilizing prices, it is a problem.

Physical and Economic Factors

High Peak Loads

The period of the highest prices coincided with a period in which loads in the Northwest, California and the Desert Southwest were at high levels as a result of high temperatures throughout the West. In the Northwest, peak loads were approximately 3,400 MW greater than last year while in California on the same day loads were approximately 1,400 MW higher. [California and the U.S. portion of Northwest Power Pool (NWPP) combined, increased 4,826 MW from the peak on June 30, 1999, to the peak on June 28, 2000, both Wednesdays.]

Unusual Hydropower Production

While the summer of 2000 was expected to be a more or less normal year in terms of overall runoff in the Northwest, the runoff came in an unusual pattern. Runoff in the early spring was somewhat higher than usual. But in May and particularly in June, the runoff and hydropower generation was less than normal and much less than 1999. Hydropower generation in late June was approximately 6,000 MW less than the same time in the previous year.

Planned and Forced Outages of Thermal Units

Maintenance on thermal generation is frequently planned for the May-June period when abundant hydropower is typically available. In addition, plants do break down, sometimes when it is least desirable to do so. We have attempted to identify Northwest thermal units that were either on planned or forced outage status during the last week of June. This was done by examining the generation data reported to the Western Systems Coordinating Council (WSCC) or sup-plemental data that was provided by Northwest generators. These combined data sets comprise about 85% of the capacity in the Northwest. From these data it appears that approximately 1,670 MW of capacity was out on a long term basis, either planned or extended forced outages, and another 3,400 and 2,700 MW experienced short-term forced outages on the 27th and 28th respectively. Total generation, thermal and hydro, for the last week of June was approximately 4,000 MW below the levels of 1999.

Load/Resource Balance for the Northwest

A preliminary analysis of loads and resources for the Northwest Power Pool - US Systems for June 28, the peak price day of June, indicates a peak net hourly load (native load plus exports) of about 41,000 MW. We were unable to identify more than 38,000 MW of capacity, including imports, available to meet these loads. This analysis has a high level of uncertainty (hourly operating data was available for about 85% of installed capacity and the output of the remaining installed capacity had to be estimated and data errors are possible). Obviously, since the lights did not go out, the system was able to balance loads and resources. It is likely that data errors and errors in our estimates for the non-reporting generators are at fault. Nonetheless, the evidence strongly suggests that the Northwest was operating under near-deficit conditions during the heavy-load hours of that day.

Gas Prices

Between the summer of 1998 and the summer of 2000 natural gas prices at Sumas (on the Washington-British Columbia border) increased from about $1.50 per million Btu to $3.30. Prices into Southern California increased over the same period from about $2.40 to $4.18. Prices have moved substantially higher during late August and September. During mid- September, prices at Sumas were $4.60 and prices into Southern California were over $6.00, although the California prices were affected by a serious pipeline explosion.

Higher natural gas prices, should they persist, will result in higher "normal" prices of electricity. Depending on the generating technology used, a $2 dollar increase in natural gas prices (roughly consistent with the doubling of gas prices seen by mid-summer) could increase electricity prices by between $15 per megawatt-hour and $22 per megawatt-hour. Average electricity prices during high load hours in the Pacific Northwest mid-Columbia market increased by $140 per megawatt-hour between June 1999 and June 2000, and light load hour prices increased by $46. The comparable price increases in Southern California were $113 and $28. The increase in natural gas prices can not come close to explaining the observed increase in electricity prices.

Factors Related to the Immaturity of the Competitive Electricity Market and the Uncertainties in the Transition from a Regulated Structure

Lack of Price Responsive Demand

A systemic problem associated with the immaturity of the competitive electricity market is the lack of a demand side to that market. Price responsive demand is important to an efficiently operating competitive market. Price responsiveness is an essential mechanism to balancing supply and demand. Without some degree of demand responsiveness, there is no check on the prices that can be charged when supplies are tight, except for artificial caps. This is particularly critical when supplies are stretched to their limits. Under those circumstances, a relatively small degree of price responsiveness can have a relatively large reducing effect on prices, and could also mean the difference between maintaining service and curtailments

Currently, at any given hour, the amount of electricity demand is virtually independent of wholesale price. This is because the vast majority of electricity consumers do not see market prices in anything approaching real time and, for the most part, have done little if any thinking about how they could reduce their demands if power were very expensive. The NWPPC is not advocating retail access as means of achieving price responsiveness. The states are making their decisions about when and how much to open their retail markets to competition. But developing price responsive demand does not require passing real-time market prices on to all consumers. It does mean, however, that those the suppliers who do see wholesale prices should act as intermediaries between the market and consumers to effect load reduction or shifting that is in the mutual economic interest of the consumer and the power system. We believe this will develop in time and that the current high prices will help motivate that development. However, given the tight supplies and high prices now affecting the market, the NWPPC believes that special effort should be devoted to encouraging and facilitating the expedited development of the demand side of the market now.

The California Effect

Among the Western States, California's electricity industry is farthest down the restructuring path. Their path is, in many ways, quite different than most other examples. They have created a market structure that is quite centralized and quite complex. For most of its three-year life, the California market demonstrated competitive power prices. However, under periods of stress, we believe there are characteristics of the California market structure and the incentives it creates that arguably result in prices that are higher than they might otherwise be. The California Independent System Operator (ISO) and experts acting in an advisory capacity to the ISO have identified these characteristics. These include restrictions on the ability of California utilities to enter into longer-term contracts, thus forcing most loads into day-ahead and hour-ahead spot markets operated by the California Power Exchange. Other facets of the market design create incentives that, when supplies are tight, result in as much as 20% of the load being met in a real-time market operated by the ISO. This is not a situation conducive to moderating price spikes. We know California is studying these issues and we are hopeful that they will resolve them in a satisfactory fashion.

Did Market Participants Manipulate the Market?

Much is made of market participants exercising market power during this summer's price spikes. Clearly the prices we have seen are well above a "competitive" price, if that is defined as the operating cost of the most expensive unit on the system that must run to meet load. The ability of market participants to ask for and receive more than the competitive price can be defined as market power. However, this is also the normal functioning of a market when supplies are tight and there is no moderating effect of price responsiveness. It is neither illegal nor immoral.

The NWPPC did examine the generating records of most Northwest power plants to see if there was evidence of manipulating the market by "withholding," i.e., holding power off the market to drive up prices. We found no clear evidence of such behavior. Power plants were generally being operated as one would expect given the characteristics of the plants. Hydro plants were typically following load. Thermal plants were typically running "flat out" or, in the case of units with higher operating costs, backed down during the off-peak periods. Where there were operating patterns that might be interpreted as withholding, the quantities involved were too small to affect the market.

The NWPPC did not have access to information that would permit analysis of the bidding strategies of different market participants. We do not know whether that information would suggest market manipulation.

Recommendations

Encourage the Greater Use of Risk Mitigation Mechanisms

One of the characteristics of a commodity market is the emergence of mechanisms to manage risk, and electricity is rapidly becoming a commodity market. These mechanisms include actual physical longer-term contracts for supply, futures contracts, financial hedging mechanisms, and so on. These mechanisms can limit exposure to high prices. At the same time, however, there is always the risk that they will prove more costly than the spot market. Risk mitigation comes at a cost, and it is not realistic to be fully hedged for all risk. But the experience of this summer suggests there could be greater use of risk management tools.

As noted earlier, we believe the limitations on forward contracting by California utilities was a contributing factor to the price extremes of this summer. We believe the same is true of other market participants in the Northwest and elsewhere. While opportunities to enter into forward contracts and other hedging arrangements have existed, it may be that the protracted period of low market prices for electricity lulled some market participants into believing they had no need of such mechanisms. Recognizing the commodity nature of the electricity market and taking appropriate steps to protect against the upside risk is important. Had more market participants done so, it is likely that this summer's price volatility and its impacts would have been moderated. Forward contracting is also a vehicle by which new entrants in the generation market can limit their downside risk, thereby facilitating the development of new generation.

Evaluate the Need and Options for Further Encouraging Generation Development

As noted earlier, the NWPPC's analysis of power supply adequacy indicated that market prices would not be sufficient to support the development of "merchant" power plants, i.e., plants selling into the spot market exclusively, until 2004. The NWPPC has also done analyses looking at actual market prices over the past year to see if prices had been sufficient for a new entrant to cover its variable operating costs and its fixed costs and earn a reasonable rate of return. Until this summer the answer has been "no."

With the electricity and gas prices experienced over the past year, the answer has become "yes." With the higher prices, a couple of plants not considered in the NWPPC's adequacy study have begun construction. In the Northwest, there are now 1,276 MW of capacity under construction that should come on line in 2001 through 2002. There are another 2,977 MW that already have site certificates, 1,291 MW of which we judge to be "active" projects, and another 3,060 MW that are in or have begun the siting process. The siting process does not appear to be a problem in that there is a backlog of sites that have been permitted and many more in the process. Almost all of these are natural-gas-fired combustion turbines, and nearly all of them are located within reasonable proximity to natural gas pipelines and transmission lines. There is a similar story to be told elsewhere in the West.

The degree of developer activity is encouraging. However, if we were to experience a couple years of relatively warm, wet winters and cool summers with good hydro conditions, market prices would probably fall and many of the active projects might become inactive. If followed by a dry spell and a hot summer or a cold winter, we would be up against the supply limits again.

The question this possibility raises is whether we can rely on the market to provide sufficient capacity for reliability purposes. And if not, what are the options for assuring that there is capacity available to assure reliability and mitigate excessive price spikes? The NWPPC intends to pursue this question.

Accelerate Efforts to Develop the Demand Side of the Market

While the lead-time for the development of new combined cycle generation is relatively short, development will take some time. During that time, the region and the West are vulnerable to further price spikes and possible reliability problems. Moreover, it is not certain that the long-term market will support the level of development necessary to assure adequate reliability. Developing the demand side of the market has the potential for somewhat shorter lead times. Price-responsive demand can help mitigate price spikes and potentially avert reliability problems.

The Northwest has a great deal of successful experience in increasing the efficiency of electricity end-use as a resource. The region needs to reinvigorate those efforts in light of the market prices we are experiencing. There are cost-effective means of slowing the growth of demand that should be exploited. However, the region in particular needs to move aggressively to implement price-responsive demand management – reducing loads during periods of high prices or shifting the loads to periods of the day where prices are less. The bad news is that this region has relatively little experience with these approaches, although that is changing. The good news is that there should be significant untapped potential.

The NWPPC believes that market-like mechanisms wherein the consumer receives a significant part of the benefit will be most effective. Pilot programs have been initiated this year in the region in which the serving utility and the load-reducing consumer share the cost savings of avoided power purchases (or the revenues from selling the freed-up power on the market). These programs appear to have been successful although limited in scope. The greatest potential for such partnerships probably exists within industry and large commercial buildings. What can be done will vary from building to building and process to process. Nevertheless, if provided the incentive, the NWPPC believes people will rise to the challenge. Creating these incentives should be a priority for the utilities of the region.

California Should Correct the Incentives in their Market Structure that Contribute to Excessive Prices and Volatility

The NWPPC believes that the California ISO and others in the California market have done a credible job of identifying the barriers and incentives created by their market structure that have contributed to excessive prices and price volatility. We know the issues are complex and politically volatile. We hope that the state can move quickly to correct these problems.

At Least Until the Market Matures, Data for Monitoring and Evaluating the Performance of the Market Should be Available on a Timely Basis

One thing that the experience of this summer has shown is that it is difficult to obtain the data necessary to monitor and evaluate the performance of the market. Despite the fact that utilities in the Northwest were extremely cooperative, there was a delay of many weeks before the relevant data could be obtained. While the WSCC maintains a data base of generation and transmission loading data, not all generators report to the system and of those that do, the data link is not necessarily carefully maintained. Despite incompleteness data, the WSCC has chosen not to release the information to independent body like the NWPPC, even when it agreed to keep the data confidential and to use the data in such a way that individual plants could not be identified. We understand the possible commercial sensitivity of some of this information. We believe, however, that there should be arrangements possible that both protect the commercial value of the information and make it possible for responsible independent parties to evaluate market performance on a timely basis. At least until the market has matured and the public has greater confidence in its operation, this should be a high priority for market participants and organizations like the WSCC, the California ISO and regional transmission organizations as they are formed.

Electricity Emergency Process and Procedures Need to be in Place

If we are correct is our assessment that the electricity market prices experienced this summer are a warning of approaching scarcity, then establishing the processes and procedures that would be used in the event of an actual supply emergency should be a priority. Until new generation comes on line and demand-side programs can be implemented, there is significant probability that our emergency readiness will be tested. Necessary elements include an inventory of the actions that could be taken, the trigger points for taking these actions, clear definition of roles and responsibilities, and a communications plan to inform the public. We are pleased that efforts to accomplish this are underway involving the Pacific Northwest Utilities Conference Committee, the Northwest Power Pool, Bonneville Power Administration, the NWPPC, the Northwest states and region's utilities.

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[1] The full report, plus additional background information is available at the Northwest Power Planning Council's website: http://www.nwppc.org/adeq_toc.htm. Council Document 2000-18.

[2] *Northwest Power Supply Adequacy/Reliability Study, Phase 1 Report*, Paper 2000-4, Northwest Power Planning Council, March 6, 2000, Council Document 2000-4..

Section B
Transmission

Introduction

The institutions that govern the regional electricity transmission grid which serves Washington and other western states are in the midst of a significant restructuring. As a result of changes in federal policy and ongoing industry-sponsored processes here in the west, new institutions are forming that will fundamentally alter the way the transmission system is governed, operated, planned, and expanded.

Transmission systems have traditionally been owned and operated by vertically integrated utilities which use them to deliver power from their own generators to their distribution systems. The Bonneville Power Administration (BPA) owns and operates some 80% of the high-voltage transmission line-miles in the four Northwest states. Additional transmission systems are owned by publicly-owned utilities and investor-owned utilities under the regulation of state public utility commissions, and the Federal Energy Regulatory Commission (FERC). Grid reliability is maintained through a system of voluntary rules developed by industry organizations.

In the 1990s, the federal focus shifted to facilitating a competitive wholesale power market. New federal rules required utilities to open up their systems to use by competitors, and encouraged the formation of new regional entities for managing the region's power grid, while in 1999 legislation was introduced in Congress to establish mandatory, enforceable reliability rules.

While transmission costs account for only about 10% of the typical retail electric bill in Washington, the policies that govern the electricity transmission grid can affect the public interest in a number of significant ways. Ensuring that the interstate transmission grid is operated reliably is the most obvious, and most important. Outages on the transmission grid have the potential to affect power supplies for millions of customers, and can result in economic losses in the billions of dollars. Transmission policies are also extremely important for the development of new generating resources, as the availability and price of transmission will affect the timing and location of new power plants. Transmission policies can either encourage or discourage the development of new renewable resources and alternatives to new transmission lines such as demand-side management and distributed generation. For these and other reasons, it is critical that the public has involvement in major decisions regarding the planning and operation of the region's transmission system.

Changes in grid management organizations are largely proceeding on two parallel tracks: the efforts by regional utilities to form a Regional Transmission Organization, RTO West, in response to the FERC's Order 2000; and an effort to merge a number of industry groups dealing with reliability and commercial practices into a single westwide organization.

Background

The current grid management system began to take shape in the mid-1960s, after the interconnection of the western system was completed. The Western Systems Coordinating Council (WSCC)[1] was formed in 1967 in the wake of a blackout in the Northeast that left almost 30 million people without power. The WSCC is one of ten regional reliability councils that operate under the auspices of the North American Electric Reliability Council (NERC)[2]. The goal of NERC is to enhance the reliability of the bulk power system through the development of voluntary standards that govern the way interconnected utility systems interact with each other. The WSCC is the only regional reliability council that governs an entire electrical interconnection (See Figure 1).

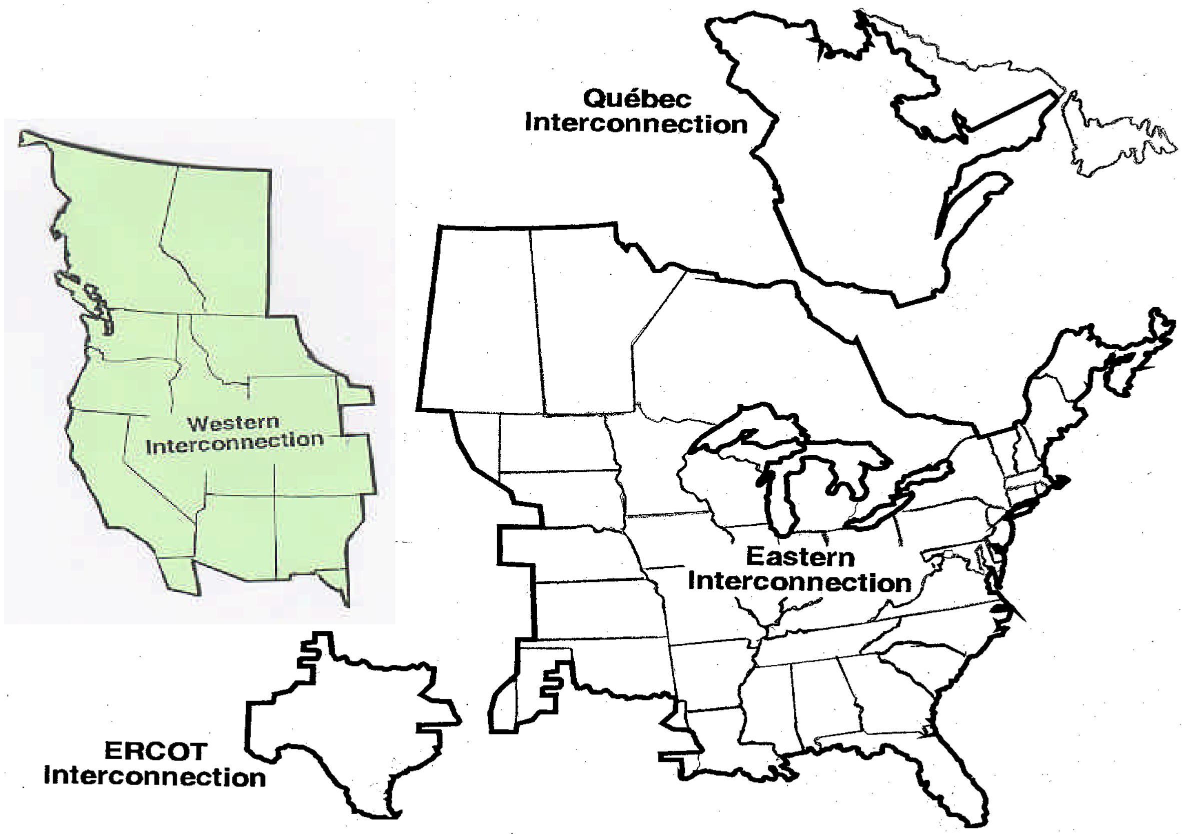

Figure 1. Electrical Interconnections in North America

With the passage of the Energy Policy Act of 1992 and subsequent policy direction from the FERC[3], industry attention turned from simply maintaining bulk power system reliability to facilitating commercial transactions among utilities and growing numbers of independent power producers (IPPs), power marketers, and other non-utility entities. The Western Regional Transmission Association (WRTA)[4],

Northwest Regional Transmission Association (NRTA)[5] and Southwest Regional Transmission Association (SWRTA)[6] were formed in the mid-1990s with the explicit goal of facilitating "open access" to utility transmission systems. Members of the RTA's are obligated to file open access tariffs if requested by another member, and are subject to mandatory dispute resolution over the terms of such access.

Order 888 and IndeGO

The goal of open access was furthered in 1996 when FERC issued Order 888 ("Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities")[7]. Order 888 and its companion Order 889[8] required each utility to post any transmission capacity not needed to serve their own customers under state-regulated retail tariffs ("available transfer capability" or ATC) on an on-line bulletin board, and to sell such capacity to any qualified customer under standard terms spelled out in a FERC-approved tariff. Further, the orders required utilities themselves to reserve capacity on their own systems under the same FERC-approved tariff for their customer's use. This requirement was intended to blunt the advantages utilities enjoy in the wholesale market by virtue of owning and operating high-voltage transmission systems.

Order 888 did not require utilities to form Independent System Operators (ISOs), but it did encourage utilities to consider taking that step. ISOs are independent organizations which take over operation but not ownership of the high-voltage transmission systems of several utilities. The Order also contained a number of recommendations should utilities decide to form ISOs voluntarily.

The Northwest began to have earnest discussions about forming an ISO beginning in 1995. The 1996 Comprehensive Review of the Northwest Energy System[9] sponsored by the four Northwest governors recommended that an ISO be formed in the Northwest, comprising the high-voltage systems of the BPA and the region's Investor-owned Utilities (IOUs). In August of that year, the six IOUs announced their intention to form an ISO called IndeGO. The IOUs were soon joined by BPA and a number of publicly-owned utilities, in addition to utilities in Colorado and Wyoming. Negotiations during 1997 produced a proposal that contained many of the elements that FERC would later include as requirements for Regional Transmission Organizations (RTOs) in Order 2000, including an independent governing board, sole authority over real-time grid operations and a market mechanism for allocating access to the grid during times of heavy use. However, concerns about cost shifting and the lack of perceived benefits in a region which is heavily dependent on low-cost hydroelectric power led to the proposal's abandonment in early 1998.

Merging Western Grid Management Organizations

The shelving of the IndeGO proposal did not end momentum to reorganize the institutions that manage the western grid. While the formation of the RTAs filled the need for a forum in which users of the grid could discuss commercial issues, it was recognized early on that issues which had traditionally been thought of as "reliability issues" could have enormous commercial ramifications while certain commercial practices could well have an impact on grid reliability. In 1997, the RTAs, the WSCC, the Colorado Coordinated Planning Group, and the Committee on Regional Electric Power Cooperation (CREPC) (a committee of the Western Governor's Association consisting of energy agencies and utility regulatory commissions in western states and provinces, including the OTED Energy Division)[10] formed the Western Interconnection Forum (WICF)[11], an ad-hoc group whose role was to coordinate among the various organizations and to study whether and how to combine them into a single, west-wide grid management organization.

Meanwhile, a NERC-sponsored "Blue Ribbon Reliability Panel" were recommending changes in the way reliability is governed at the national level.[12] The commission recommended that Congress pass legislation granting the authority for setting mandatory reliability standards to a new, self-regulating reliability organization (SRRO). The new body, to be called the North American Electricity Reliability Organization (NAERO), would supplant NERC and would provide an umbrella under which regional reliability organizations (RROs) would enforce standards set by the NAERO. Western interests, including states and provinces, pushed for additional deference to standards set by RROs that encompass entire interconnections, such as the WSCC, and for a greater role for states and provinces in the governance of RROs and in the standard-setting process. Legislation (S.2071 Electric Reliability 2000 Act) to accomplish all this passed the United States Senate in 2000, but stalled in the House of Representatives.

The WICF work group met throughout 1999 and into 2000 to develop a proposal to create a western RRO, provisionally dubbed the Western Interconnection Organization (WIO). The WIO would mirror the structure and functions of the NAERO, setting reliability standards for the western interconnection, and addressing commercial issues through a market interface committee. Work was completed on this proposal in the fall of 2000. The proposal was endorsed by the CREPC and the WRTA in October of 2000, and by NRTA in November, with additional presentations to the other organizations scheduled. Regulatory approval is expected in mid-2001, with incorporation and merging of existing entities by the end of 2001. More information about the proposed WIO can be found at http://www.wrta.net/wicfdocs.htm.

Order 2000 and RTO West

While FERC's Order 888 contained a number of recommendations for the formation of ISO's, it did not explicitly require that utilities take that step. Several ISOs did form around the country, mostly in regions where states had opted to restructure their retail markets. By 1999, ISOs were operating in California, New England, New York, and the PJM region (consisting of Pennsylvania, New Jersey, Maryland, and Delaware), and discussions were underway in the Midwest and Desert Southwest. In 1999, FERC undertook a series of conferences, informational proceedings, and consultations about the next steps for transmission restructuring. These led to the issuance of a notice of proposed rulemaking (NOPR) in May of 1999. In the NOPR, FERC proposed that utilities be required by October 15, 2000, to file plans to form RTOs, to be operational by December 15, 2001. Utilities would also be given the option to make alternative filings consisting of explanations for why they were not filing RTO plans. The rulemaking was finalized in December of 1999, as Order 2000.[13]

Northwest parties had been discussing a variety of options for future transmission organizations, from an independent grid scheduler, which would do little more than serve as a clearinghouse for transmission capacity, to a "TransCo", which would own and operate the region's high voltage grid. In March of 2000, nine transmission-owning utilities ("filing utilities") kicked off a public process that led up to the October 16 filing of RTO West.[14] The filing utilities are Avista Corporation, BPA, Idaho Power, Montana Power, Nevada Power, PaciCorp, Portland General Electric, Puget Sound Energy, and Sierra Pacific Power. Only the eight investor-owned utilities are subject to FERC jurisdiction and, hence, to the requirements of Order 2000, but BPA participated on a voluntarily basis. The utilities formed a "regional representatives group" (RRG) of stakeholders to advise the filing utilities as they prepared a filing that would meet the requirements of Order 2000. Stakeholders represented on the RRG included independent generators, power marketers, several different groupings of publicly-owned utilities, end-use customers representatives, environmental and renewables advocates, and state and provincial energy agencies. Given the lack of time before the October 16, 2000, deadline, the parties were to use the IndeGO proposal as a jumping-off point. The filing utilities also issued consensus statements regarding the form, structure, and functions of the proposed RTO to further frame the debate.

The proposal that emerged from this process will, if accepted, fundamentally alter the way the bulk power system is operated and the way expansions of the system are planned and financed. Traditionally, transmission systems have been owned and operated by vertically integrated utilities which use them to deliver power from generators they own to distribution systems they own. Operational decisions are made with an eye towards minimizing company-wide costs, subject to voluntary constraints on the way in which operations can affect neighboring systems. Investment decisions are made within a regulatory framework that, in theory, offers similar incentives for competing investments, whether they involve new generation, transmission, or demand-side management.

This model began to change with the movement towards a competitive wholesale power market, and as utilities began to rely on purchases from independent suppliers to meet load growth rather than investing in new resources of their own. The decentralization of the generation planning and investment process, coupled with continued uncertainty on the part of vertically-integrated utilities as to the nature of their relationship with retail customers over the long run, calls into question whether existing planning processes are adequate to provide for the infrastructure needs of tomorrow's industry.

RTO West would complete the transition to a new industry structure in which the transmission system would be operated by an entity that is independent both from generators and from retail energy service providers. RTO West would be governed by a nine-member board of directors, who can have no financial ties to any member company. While principle responsibility for planning and constructing local transmission facilities would remain with participating transmission owners, RTO West would have a role in planning main grid additions, and would have backstop authority to compel a transmission owner to construct a facility that is needed by a third party. Facilities whose primary purpose is to facilitate power trading, rather than to provide reliable service to load, would be financed through some sort of market mechanism, rather than by existing transmission ratepayers.

Operationally, the biggest changes would be in the way transmission capacity is reserved and in how ancillary services are procured. Currently, transmission service is purchased under a hodgepodge of long-term contracts and shorter term arrangements under Order 888 tariffs. Generators that wish to schedule power to a neighboring control area must pay a cost-based transmission tariff to obtain transmission service to a control area boundary. Additional tariffs must be paid to each control area operator between the generator and its customer, resulting in one or more transmission rate “pancakes”. Ancillary service products such as regulation and operating reserves are provided for a fee by transmission owners, from their own generators if they prefer. Transmission rights are not easily tradable, which means that if transmission schedules need to be curtailed due to “congestion” (when there is more demand for transmission capacity than the system can accommodate), higher-value transactions can be bumped in favor of lower-value ones. Further, because transmission schedules don’t reflect the way the power actually flows across the grid, curtailments may affect many more megawatts of schedules than is necessary to solve the problem.

In accordance with Order 2000, RTO West would institute a market-based system of rationing access the grid during times of congestion, using Firm Transmission Rights (FTRs) across designated “flowpaths” (transmission paths that experience “commercially significant” amounts of congestion). FTRs would be standardized, tradable instruments representing the right to transmit a specified amount of power across a particular flowpath in a particular direction, including standardized provisions in the event of facility outages. Aside from purchasing the necessary FTRs and providing transmission losses, there would be no charge to schedule across the grid. Establishing standardized, tradable transmission rights and eliminating pancaked transmission rates is meant to facilitate the development of a more liquid short-term market for transmission capacity, making it much more likely that scarce capacity will be allocated to the highest value use and enhancing the efficiency and competitiveness of regional power markets.

This cannot be accomplished without some impact on existing uses of the grid. Eliminating pancaked rates requires changes in the current system of allocating the fixed costs of the transmission system. Similar to the IndeGO proposal and the methods used by other ISOs, RTO West is proposing fixed, annual load-based “access fees” based on the load’s contribution to monthly peak demand. However, while the IndeGO proposal would have blended costs within certain areas over a ten-year period, resulting in transmission rate changes for some utilities of up to 0.2 cents per kilowatt-hour, RTO West opted for a system of “company rates” which it hopes will mitigate cost shifts to the maximum extent possible. Historical payments between utilities associated with transmission capacity or “wheeling” arrangements are converted into “transfer payments” which will continue for at least ten years. Utilities with pre-existing contracts or load-service obligations may also be allocated FTRs commensurate with those obligations.

In the October filing, the filing utilities asked FERC for a declaratory order by January 31, 2001, with respect to certain governance documents including the Articles of Incorporation and the By-laws, and whether the scope and configuration of the RTO as proposed meets FERC standards as articulated in Order 2000. A "Stage 2" filing will be prepared in the spring of 2001 that will contain significantly more detail about various aspects of RTO West operation such as congestion management, market design, and roles of various parties in planning and expanding the system, as well as a timetable for RTO West to begin operations. Additional filings with state regulatory commissions will probably occur after the Stage 2 FERC filing. RTO West is not expected to be operational before mid-2002.

TransConnect

In addition to forming RTO West, six of the filing utilities are also proposing to divest their transmission assets to a new company called TransConnect, LLC. The six TransConnect utilities are Avista Corporation, Montana Power, Nevada Power, Portland General Electric, Puget Sound Energy, and Sierra Pacific Power. TransConnect would be wholly owned by the six participating companies, in shares equivalent to the value of the assets contributed. A separate company called TransConnect Corporate Manager, Inc. would be formed as a publicly traded corporation for the purpose of operating the facilities owned by TransConnect, LLC. The TransConnect utilities hope this arrangement will meet FERC's requirement for independence for a transmission-only company, and that this will allow TransConnect to take on certain of the RTO functions specified in Order 2000. TransConnect's October 16 filing describes an enhanced role in the system planning and expansion process and its intention to file for some form of performance-based ratemaking, which may entail incentives to operate the systems more efficiently and/or more reliably. The TransConnect companies have asked the FERC for a declaratory order in 2001, that the proposal for governance meets the requirements of Order 2000, and that the functions TransConnect proposes to take on are acceptable.

[1] For more information about the WSCC, see http://www.wscc.com.

[2] For more information about NERC, see http://www.nerc.com.

[3] For more information about FERC, see http://www.ferc.fed.us.

[4] For more information about WRTA, see http://www.wrta.net.

[5] For more information about NRTA, see http://www.nrta.org.

[6] For more information about SWRTA, see http://www.swrta.org.

[7] http://www.ferc.fed.us/news1/rules/pages/order888.htm.

[8] http://www.ferc.fed.us/news1/rules/pages/order889.htm.

[9] http://www.nwppc.org/crfinal.htm.

[10] For more information about CREPC, see http://www.westgov.org/wieb/crepnew2.htm.

[11] For more information about WICF, see http://www.wrta.net/wicfindx.htm.

[12] For more information about the NERC Blue Ribbon Reliability Panel, see http://www.nerc.com/~blue/index.html.

[13] http://www.ferc.fed.us/news1/rules/pages/order2000.htm.

[14] For more information about the RTO West public process and proposal, see http://www.rtowest.com.

Section C
Regional Electricity Issues and the Bonneville Power Administration

Volatility turning into stability and then turning once again into volatility is a good way of characterizing the last two years of the Bonneville Power Administration's (BPA) financial and political condition. Since over one-half of all electricity sold in Washington comes from BPA, Washington has a large stake in BPA's financial and political health. This section summarizes the current status of key issues confronting both BPA and the state of Washington.

Subscription and Rates

Following the recommendation of the Comprehensive Review of the Northwest Electricity System in 1996,[1] BPA developed a Strategy for how its customers would "subscribe" or sign up for the power products it sells. The final subscription strategy, which was released in December, 1998, set forth the principles under which power would be sold to the various customer groups, how much power each would get, and what products BPA would offer for the rate period from October 1, 2001, to September 30, 2006. BPA then conducted a formal rate case that implemented the subscription strategy and set the rates for its power products.[2] The rate case concluded in the Spring of 2000 but before BPA could send its final documentation to the Federal Energy Regulatory Commission (FERC), prices for market power on the West Coast rose precipitously, rendering the cost projections for its own power purchases out of date and causing a surge in demand for BPA preference power by Northwest public utilities.

BPA, after another regional consultation, reopened its rate case and published a new version of its Cost Recovery Adjustment Clause (CRAC) which includes a 15% rate increase at the outset and will allow BPA to raise rates further if its financial reserves are projected to fall below specified levels. The proposed rate structure will place BPA's preference firm rate, the rate at which it sells wholesale power to consumer owned utilities, at 25.5 mills/kWh (or $0.025/kWh). While high for BPA, this rate is well below average wholesale long-term contract rates almost everywhere in the United States and well below current and expected wholesale market prices. (See Figure 2[3]) The rates are now expected to be final by spring, 2001. In the meantime, BPA has executed contracts with all of its Pacific Northwest customers who will have the opportunity to change their minds if the final rate schedules are not to their liking. Since BPA preference rates are likely to be below projected prices for power from other sources, it is unlikely that any customers will change their minds. There is still controversy over how power is allocated among customer classes and whether the customer classes are treated fairly. For example, the economic viability of many of the direct service customers, principally aluminum smelters, is very much in question and they want some relief. There is also a risk that higher West Coast wholesale electricity prices will drive the cost of BPA's power purchases high enough to lessen its competitiveness.

These straightforward narratives of administrative process belie the intense negotiations and even conflict that has accompanied the issue every step of the way. Seven major issues stand out. In most cases, Washington has been supportive of BPA's attempts to find a middle path among the contending forces. This is not surprising since Washington citizens are the biggest beneficiaries of BPA power and Washington contains all the contending regional interests within its borders. The issues are:

1. **The battle among customer groups, public utilities, aluminum companies, and the residential customers of the investor owned utilities for shares of preference power**

   Since BPA has not acquired any new generation resources in many years and

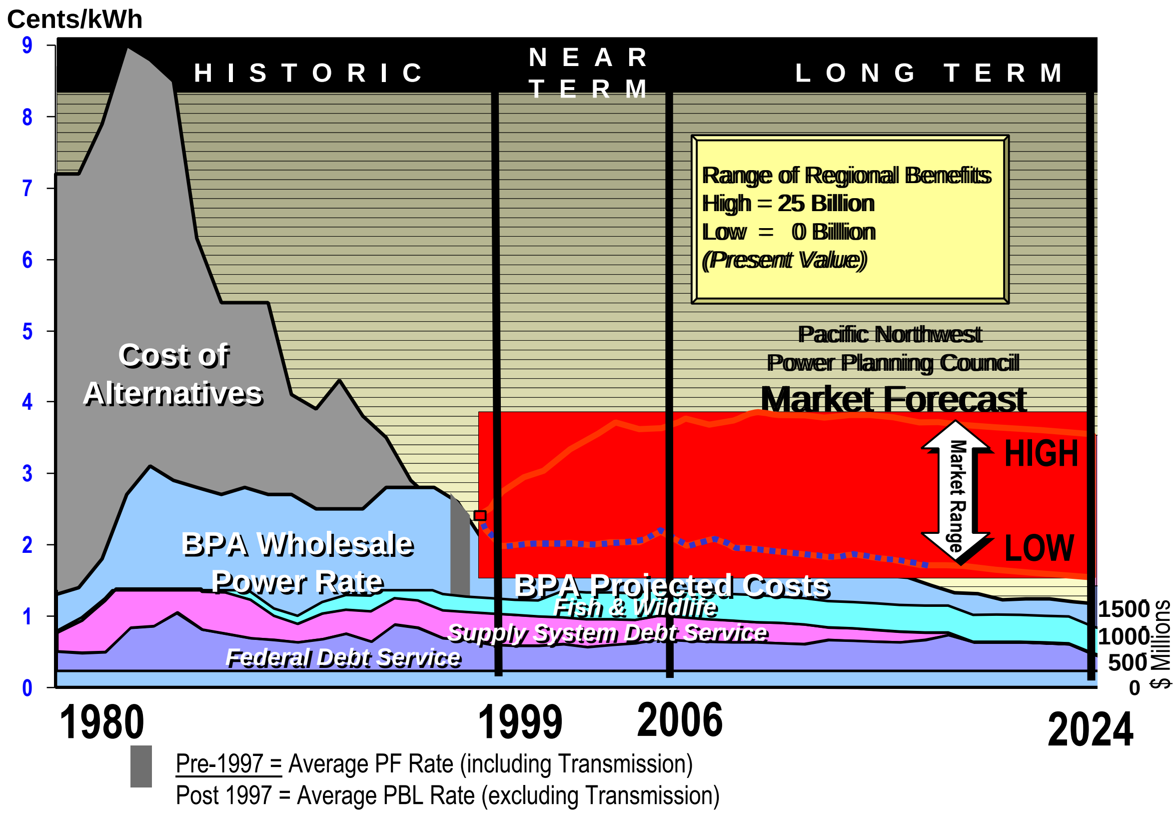

Figure 2. BPA Cost Based Rates and Range NWPPC Forecast Rates

Source: BPA, June 1999

operation of the hydro system for fish recovery has reduced its available power, BPA supplies less and less of regional power demands. On the other hand, demand continues to rise and as BPA becomes cheaper and cheaper relative to other resources (despite the rate increase), all customers want larger shares. BPA ultimately proposed to meet all public power loads (it is required to by law), half of residential Investor Owned Utilities (IOU) loads (partly with power and partly with an equivalent payment in cash), and about half of aluminum company loads. This was a shift away from aluminum companies toward residential customers of IOUs, while raising rates for all of its customers since BPA will have to buy power on the market to meet all of its commitments.

2. Fish costs

Generally environmentalists and tribes wanted BPA to leave room in its rates for higher costs and expenditures for fish recovery up to and including the costs of removing the four lower Snake River dams. All customer groups generally supported lower financial commitments to fish and wildlife recovery. BPA pretty much split the difference and neither set of interests came away fully satisfied.

3. Slice

Responding to requests from public utilities that generate much of their own power, BPA agreed to sell some power as "Slice." Slice means "slice of the system" and purchasers agree to receive a fixed percentage of the output of the system (rather than a fixed amount of electricity) at any time and, in return, commit to pay that same percentage of BPA's costs. The negotiations over Slice were both highly technical and political. The political issues produced some familiar fissures. Washington supported ten year contracts on the grounds that a longer term is essential to even out the risks to both BPA and the utilities while Oregon and California argued that such long contracts would lock up the system and make it harder to make the policy and governance changes they sought. There were new disagreements as well. Since Slice contracts benefit those public utilities who generate some of their own power while also buying from BPA (they are known as partial requirements customers), the full-requirements customers (those generally smaller utilities who buy all of their power from BPA) were afraid that the Slice "product" would shift more of BPA's costs to them. Ultimately, BPA again found a compromise: rules that satisfied the full-requirements customers, a contract length of ten years, but a cap of how much electricity could be sold as Slice, 2000 aMW.

4. Contract length

The controversy over the length of Slice contracts was part of a larger controversy over the length of contracts in general. BPA is authorized to sign contracts of up to 20 years and, until recently, all contracts were routinely twenty years long. The new subscription process and rate case came about because of the expiration of the twenty-year contract period that began on October 1, 1981, (although all of the aluminum companies and many utilities had renegotiated the terms of their contracts in 1996.) Washington State generally supported the full-requirements customers and other utilities that wanted very long-term contracts in the belief that one of the best ways to preserve the benefit of the Federal Columbia River Power System (FCRPS) for the state and region is to make a long-term commitment to it. Generally all interests that sought changes in how the system is governed and how the benefits are distributed preferred shorter contracts. Thus, Oregon and Montana, aluminum companies, members of congress from the Northeast and Midwest states, and California, and tribes wanted contracts of three to five years. Ultimately, BPA signed contracts of up to ten years with utilities that wanted them and five-year contracts with aluminum companies.

5. Restructuring

Restructuring legislation in Oregon and Montana caused more interstate tensions. In Montana, there was confusion about what utility, if any, should serve the former customers of the Montana Power Company and how the BPA residential exchange process should be handled. The Montana legislature authorized a buyers cooperative to purchase power on behalf of residential and small business customers formally served by Montana Power but BPA refused to acknowledge it as a utility because it did not own utility poles and wires. Consumer owned utilities in the region (and the state of Washington) strongly supported BPA, but Oregon, which has considered creating a similar mechanism to buy power on behalf of its own IOU customers, supported Montana.

Oregon's restructuring law caused its own complications because it encouraged its IOUs to divest themselves of some of their resources, thus reducing their "net requirements" and hence their eligibility for power purchases from BPA. Oregon's law also contains a provision that requires the Oregon Public Service Commission (PSC) to place a hold on the implementation of the restructuring if it appears the Oregon consumers would not receive the benefits from BPA to which they would otherwise be entitled. Ultimately, BPA found pathways to get residential exchange benefits to Montana and Oregon consumers without changes in BPA rules. In the case of Montana, all parties agreed that any successor utility to Montana Power would inherit Montana's share of residential exchange benefits. In the case of Oregon, BPA and the PSC agreed to adjust the manner in which residential exchange benefits were conveyed to

Oregon IOUs so that they could obtain the benefits in the form of more monetary equivalent payments and less in the form of actual electricity deliveries. This would have no effect on the rates Oregon customers paid but would not violate BPA's statutes regarding "requirements."[4]

6. **New public customers**

Although consumer or publicly owned utilities have the first right to BPA preference power, there have been no new consumer owned utilities created in many years. With changes in the electricity market brought about by restructuring, there is now renewed interest. BPA set aside a limited amount of subscription power for entities that want to qualify as preference customers. The Yakama Indian Nation and the City of Missoula (Montana) are among the entities most likely to qualify by acquiring a distribution system and having a financial and administrative apparatus that meets federal requirements.

7. **Conservation and renewables**

BPA included a modest conservation and renewables discount program in its new rate structure and is working on a plan to replace about 5% of its power purchases with conservation. Public interest groups and many utilities have been disappointed with both the low targets and low financial support for these programs and are dubious about the proposed implementation procedure. Washington Energy Policy staff have generally agreed. However, the conservation and renewables discount program rests on the excellent analytic work of the Regional Technical Forum, which Washington strongly supported and participated in. There seems to be universal agreement that, on this, BPA's money was well spent.[5]

Supply/Price/California/ Emergencies

Low water, high demand from California, and increased Northwest loads stretched the Federal Columbia River Power System to the breaking point during the summer of 2000. Coupled with tight electricity supplies, fast rising natural gas prices sent market prices for electricity startlingly higher. Together, the supply crisis and price spikes confirmed that both California and the Pacific Northwest need to take measures to mitigate extreme price volatility and assure sufficient electricity supplies.

Until the 2000 crisis almost all Washington consumers were insulated from short-term market volatility. The extreme price volatility affected only the few industrial customers who had to buy their power on the market or at prices indexed to the market. However, many of Washington's utilities lost money over the summer as they engaged in their usual business of buying and selling power to balance their loads and perhaps make some money. Utilities that lost money either have or will attempt to recover those losses from their customers. At the end of 2000, however, the tightness and volatility in the Westcoast electricity market, coupled with a tight and volatile natural gas market, was having an effect on all electricity consumers. BPA's initial rate increase is due primarily to having to make greatly increased purchases in a rising market. If prices do not moderate, BPA will have to invoke the Cost Recovery Adjustment Clause again and again in order to recover the costs for the purchases it must make to meet rising Northwest demand.

For BPA, by far the region's largest provider of wholesale power and the largest player on the wholesale power market, the summer of 2000 represented close calls both electrically and politically. BPA was repeatedly called upon by the California Independent System Operator (ISO) to step in when California was faced with a Stage Three Emergency (rolling blackouts). This meant that in order to prevent rolling blackouts in California, BPA had to curtail loads in the Northwest and risk violating fish-recovery protocols for operating the Columbia River system. Because BPA had to sell power into the ISO under the ISO cap rather than engage in bilateral trades that private generators and power brokers were free to engage in, BPA was unable to recover all of its own costs for buying power to meet Northwest loads. Despite its forbearance, BPA has been excoriated as a profiteer by many California elected officials who also want BPA to sell power to California public entities on the same basis as it sells power to Northwest public customers. Senators Feinstein and Boxer, along with Representative George Miller, wrote to Secretary of Energy Richardson asking him to stop BPA from signing subscription contracts until issues of regional preference could be decided. This would have, in effect, put subscription on hold indefinitely while Congress attempted to change federal law.

Washington's entire congressional delegation, as well as Governor Locke, defended BPA by writing to Secretary Richardson asking him to reject the requests from California and by directly writing to California members of congress. All other members from the Northwest also signed the letters from the delegation. The Secretary did not delay subscription and BPA informally told its California public customers such as the Bay Area Rapid Transit District that it will not recall power under contract to them.

There is another issue, the future of the DC intertie, that may strain California/BPA relationships. The Los Angeles Department of Water and Power and Southern California Edison have asked the BPA's Transmission Business Line to commit to maintaining its end of the interties at the current 3100 MW capacity for the next 30 years. BPA's cost study indicates that it is not cost effective to BPA at current transmission rates to maintain the intertie, but it would be if southern California customers were charged more. BPA is conducting a public review of this issue and decision is expected in a few months.

The December 2000 energy emergencies once again highlighted BPA's central role in the Northwest electricity picture. BPA's forecasters lead the decision to declare a Regional Energy Warning on December 8 since they would not be able to meet BPA's loads and respond to California without once again technically violating the Biological Opinion (Bi-Op), regarding Columbia River flows. Rather than importing power to serve Northwest (and especially Washington) loads, as is customary in the winter, BPA was directed by Secretary Richardson to exchange power with California in order to prevent more Stage Three Emergencies in that state. In effect, rate-payers in the Northwest are beginning to pay for the unstable power situation in California through the diversion of BPA resources to California and because California's situation pushes the West Coast wholesale market so much higher which, in turn, forces BPA to pay much more for the power purchases it has to make in order to meet load.

Fish/power Issues

According to the *Draft Fourth Northwest Conservation and Electric Power Plan 1996*, "the total reduction in firm energy generating capability of the hydroelectric system since the Council adopted its first fish and wildlife program amounts to approximately 1,200 average megawatts, representing a 10% loss."[6] The recent draft Bi-Op, published by the Federal Caucus in July 2000, proposes a smaller but still significant further reduction, especially in the winter, when regional power shortfalls are already feared.[7] The draft Bi-Op leaves on the table the option of breaching the four lower Snake River dams, but only if other measures are not successful in recovering salmon. Breaching the dams would reduce the output of the hydro system by 800-1,000 aMW or 4-5%, of regional electricity needs. Finally, during this past summer's power emergencies in California, the California ISO appealed to BPA to provide more electricity than BPA had available under the current Bi-Op. If the California situation had become dire enough that BPA had to meet the request, BPA would have been forced to violate the Bi-Op by operating the river for power rather than fish. This did not happen, but it became clear that fish recovery in the Northwest is subject to the effects of the California power market, a fact reaffirmed during the December 2000 power emergency.

Washington's policy on these issues has been led by the Governor's Salmon Recovery Office which has strenuously argued for salmon recovery options that do not breach dams and for responses to California energy emergencies that do not undercut salmon recovery efforts in Washington and the Northwest.

Transmission/RTO

BPA has voluntarily begun to comply with provisions of the 1992 Energy Policy Act and the FERC orders implementing the act by agreeing to separate its Transmission Business Line from its Power Business Line and filing a proposal with FERC to form a Regional Transmission Organization with public and private utilities in the Northwest. Since BPA is the dominant owner of transmission in the region, its decision may have large effects on all consumers of electricity. These issues are fully discussed in Section B of this chapter.

Threats to BPA/Preference

The great advantage to Washington and the rest of the Pacific Northwest of having BPA as its largest supplier of electricity has not gone unnoticed. From the start, the Federal Columbia River Power System was opposed by many in Congress on ideological and regional lines. Currently the Northeast-Midwest coalition has argued that federal subsidy of the BPA system allows Northwest industry to compete unfairly against their own. Northeast-Midwest coalition members have repeatedly introduced legislation to require that BPA (and other federal power marketing agencies) sell their power at market prices rather than at cost as they are currently required by law. Depending on the market price of electricity, such a change could cost Washington consumers up to $1 billion annually.[8] Because of the summer electricity crises, important California congressional delegation members have demanded that California get access to the BPA system on the same basis as Northwest consumers by repealing regional preference.[9]

In addition to threats coming from outside the region, there has always been controversy within the region over some of the core features of the federal legislation authorizing BPA. These controversies exist because the benefits of the system are not, and have never been, distributed equally across the region. Thus, investor owned utilities and their customers have never liked public preference (dating from the original Bonneville Project Act of 1937), the consumer owned utilities have never liked the residential exchange (passed as part of the Northwest Power Planning and Conservation Act of 1980), while both investor and consumer owned utilities have not liked the requirement to sell power to the Direct Service Industries (updated in 1980 but expiring in 2001). Finally, the four states in the region have often disagreed about whether they are getting fair shares of the benefits of the system, perceptions of fairness being driven generally by whether the state is predominantly public or private power, and the number and importance of aluminum smelters. Historical differences among the states have been compounded by restructuring legislation in Oregon and especially Montana which is changing the concept of what a utility is and thus challenging BPA's long-standing rules about what entities it can sell power to.

Interstate discord intensified during the long subscription and ratemaking processes because these are the vehicles for how benefits are distributed among customer groups and states. Governor Kitzhaber of Oregon made an important speech on September 17, 1999, at the Seattle City Club where he called for "a new governance structure for the Columbia Basin to replace the Northwest Power Planning Council." The speech encouraged both legislators in Oregon and elsewhere and a consortium of IOU's, aluminum companies, and industrial customers generally to begin discussions about how to restructure the governance of BPA. These ideas were circulated and discussed widely under the general rubric of "regionalization" and became a permanent agenda item of the Legislative Council on River Governance, which legislators from the four Northwest states created in order to have a voice in regional discussions that tend to be dominated by the executives branches of their respective states.

The idea behind regionalization is that authority over the Columbia River Power System could somehow be devolved from the federal level to the regional level, thus enabling the Northwest to secure the benefits of the system. Washington State (along with Idaho) has been very skeptical about these ideas. We have argued that first, benefits are already distributed relatively fairly by state, second, distribution among customer classes has already been changed dramatically under subscription, third, it is absurd to ask the same interests in Congress who are trying to take the benefits of BPA away from the Northwest to permanently grant them to us, and fourth, that these efforts do more to divide the region than bring it together.

With Idaho and Washington generally skeptical about making large-scale changes in the governance of BPA, it is unclear whether momentum for regionalization can be maintained. As BPA subscription and rate-making reach their conclusions, some of the urgency for re-thinking BPA governance has diminished. However, BPA promised that after subscription concluded it would be interested in participating in discussions about whether any of BPA's organic statutes should be amended and whatever unhappiness stemming from subscription will lead long-standing critics of the status quo to continue their efforts to change the system. We can be sure that public preference will continue to be under attack, both in the region and nationally, and Washington State will continue to struggle to balance the interests of the approximately 55% of its electricity customers who are clients of consumer owned utilities with the interests of the remaining 45% who are served by investor owned utilities.

We can also be sure that external threats will remain. Even though some persistent critics of federal power marketing agencies were defeated in the recent election, the regional interests and ideological viewpoints they represent will remain. Although national electricity restructuring legislation remains stalled—and the apparent failure in California may keep it stalled—there is still considerable momentum for it. The Northwest needs to remain wary since national restructuring legislation is an obvious vehicle to address the issue of federal agencies selling power to preference customers at cost, while everyone else is becoming subject to market forces. Preserving the benefits of the BPA system for the Pacific Northwest is a continuing challenge.

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[1] The Final Report of the Comprehensive Review of the Northwest Energy System is available at the Northwest Power Planning Council's website at http://www.nwppc.org/crfinal.htm

[2] These documents can be found at the Bonneville Power Administration Power Business Line web site at http://www.bpa.gov/power/p/pblspl.shtml

[3] Source of Fig.2: Bonneville Power Administration, 1999. BPA staff is updating this graph to reflect changes in western wholesale energy markets and BPA's increased need to purchase power in those markets.

[4] The Northwest Power Planning Act (1980), U.S. Code, Title 16, secs. 839(c) and (e) requires that BPA determine the "requirements" of utilities to which it sells power. BPA makes a calculation in which it determines what other resources the utility possesses to meet its loads. Whatever it lacks then constitutes its BPA requirements. Publicly or consumer owned utilities that have no resources of their own are therefore "full requirements" customers.

[5] The work of the Regional Technical Forum (RTF), including its final report on cost-effective measures for BPA's Conservation and Renewables Discount, can be found on the Northwest Power Planning Council's website at http://www.nwppc.org/rtf_toc.htm

[6] *Draft Fourth Northwest Conservation and Electric Power Plan*, (Northwest Power Planning Council, Portland, 1996), p. 4-6. This publication is also available on the Council's website at http://www.nwppc.org/plan/httoc.htm

[7] The Draft Biological Opinion can be found at the National Marine Fisheries Service website, http://www.nwr.noaa.gov/1hydrop/hydroweb/fedrec.htm#NMFS%20Hydro, although navigating the document is difficult. The assessment of the effects electricity generation were obtained from meetings and conversations with BPA and other personnel.

[8] Estimates by Washington State Energy Policy and Utilities and Transportation Commission staff.

[9] Regional Preference was enacted into law in the Regional Preference Act of 1964 and codified at Title 16, United States Code, Sec. 837. It requires that public customers in the Pacific Northwest have the right of first refusal to BPA power and that power sold outside of the region can be recalled by BPA if it is needed in the region.

Section D
Managing Washington's Demand for Electricity

Introduction

Washington State citizens and lawmakers have a strong history of statutorily supporting the efficient use of energy. As early as 1931 the first citizen initiative set forth the purpose of public utility districts to "conserve the water and power resources of the state of Washington for the benefit of the people thereof," (RCW 54.04.020). Since then, energy efficiency and conservation were similarly identified as policy objectives for a variety of local and state government entities. Least-cost planning statutes directed investor-owned utilities to serve customers at the lowest total cost; this typically placed energy efficiency as the top priority resource to be captured. However, the implementation of these policies has a mixed track record in Washington.

Electricity price increases in the early 1980s, and the passage of the 1980 Pacific Northwest Electric Power Planning and Conservation Act began an era of increasingly aggressive pursuit of managing the demand on our existing hydropower-based electricity system through energy efficiency. Beginning in 1979, the Bonneville Power Administration (BPA) led the region in implementing a wide variety of energy efficiency programs. By 1995, the region had saved over seven million megawatt-hours (MWh) of electricity, enough to displace the annual output of two 400-megawatt (MW) generators, and nearly enough to power Seattle.[1] Electricity ratepayers reaped the benefits through lower rates, because saving electricity cost less than building new generation. The environmental savings were also substantial because the resource of choice until the early 1990s was coal-fired power plants.

In the early to mid 1990s, this aggressive pursuit of energy efficiency stopped. The federal Energy Policy Act passed in 1992. This broadened the scope of competition in the wholesale electricity markets and permitted states to implement competition in retail electricity markets. While wholesale electricity markets were developing, the price for natural gas dropped. Power developers chose more efficient combined cycle turbines as their preferred generator, fueled with relatively inexpensive natural gas. Availability of some low-cost power supplies instigated a clamor by industries to restructure the electricity industry to competitive retail markets and abandon resource planning. Utilities were frequently concerned about continuing to invest in customers that may leave their system in the near future. The utility industry response in Washington was, with notable and rare exception, to immediately cut back or eliminate investments in cost-effective energy efficiency, while also discontinuing construction of any new generation facilities. Specifically, investments in efficiency in Washington State dropped by over 70% between 1993 and 1997.[2]

Meanwhile, the state legislature has not heard an electric industry restructuring bill since 1997, the Washington Utilities and Transportation Commission has never pursued restructuring through regulatory procedures, and the forecasts for natural gas prices have risen. Recent electricity supply constraints and price spikes are causing outcries in some states, such as California, to reinvigorate utility investments of ratepayer funds in energy efficiency as a strategic line of defense against rising wholesale electricity prices and constrained transmission and distribution systems. As well, there is a call to invest funds in load management programs and support construction of new generation – including renewable resources.

Additionally, the electricity demand in the Northwest is beginning to outstrip the ability of the current system to supply it. Historically, the Northwest could rely on its vast hydropower system to always provide another MWh of electricity in response to need. But after decades of economic growth in the

Northwest, with few new resources being added to the system in the last five years, the ability of the hydro system to meet peak system loads is increasingly uncertain. Many Washington utilities now buy those last increments of electricity in a very volatile spot market.

Some regions of the country have years of experience implementing programs to manage peak periods of consumer demand for electricity because those regions have been capacity constrained for decades. This concept of managing peak consumer demand for the purpose of effectively utilizing generation supplies, transmission and distribution systems, enhancing system reliability, and for minimizing power price spikes is relatively new to the Northwest. There are a variety of approaches and technologies available to utilities to manage consumer demand for electricity instead of building expensive and infrequently used generators to meet peak loads.

Facing capacity constraints is a new experience in Washington. Facing rising power costs is not new; it is reminiscent of the early 1980s. These challenges demand new policy responses if we are to continue to be able to offer affordable and reliable power to Washington's citizens and businesses. This section of Chapter 1 explores the opportunities for managing consumer electricity consumption with cost-effective energy efficiency and peak load reduction programs. Such efforts can extend the life of our low-cost power system, avoid constructing expensive power generators that are designed to only meet infrequent peak demands, and avoid subjecting our residents and businesses to unmanageable volatile power prices.

There are multiple policy implications to consider in pursuing different paths to address our capacity constrained system and our growing hunger for energy. Key issues to consider are costs and risks. In the broadest sense, who pays the costs, bears the risks, or benefits from the opportunities associated with volatile electricity markets? We may need to develop a comprehensive solution to this question in order to answer the more explicit questions related to demand management programs. Who should pay the costs of programs to reduce energy demand? Should ratepayers bear the costs and risks of volatile wholesale electricity markets if utilities do not actively pursue energy efficiency and load management programs? Who should bear the risk that the program may prove to be unnecessary or too expensive? Who receives the benefits of a successful program? As a statewide community we may want to pursue the path that will most likely provide lower cost energy services at the least risk to consumers, to reliability of the electricity grid, and to the environment.

This section of Chapter 1 includes three subsections describing ways to manage Washington's demand for electricity; Energy Efficiency, Load Management; and Strategies for Managing Peak Loads.

The Energy Efficiency subsection describes the benefits and the costs of achieving electricity consumption reductions by using electricity more efficiently. It reviews past and current achievements by Washington utilities in saving electricity and the potential to cost-effectively double our current savings. It also describes success of the four-year old Northwest Energy Efficiency Alliance (NEEA) as it brings energy efficient products and services to the Northwest.

The Load Management subsection describes consumer load patterns in the Northwest, provides a brief overview of the Western power market's influence on Washington's wholesale power prices, and examines the potential cost of and reliability benefits from managing peak loads.

The final subsection, Strategies for Managing Peak Loads, offers a description of legislation and programs that various states, utilities, or energy service providers are implementing for the purpose of reducing peak loads.

There is significant potential for managing Washington's electricity consumption through improvements in the efficient use of electricity and by implementing effective peak load management programs. However, there are very few policies in place to ensure these investments are made.

Energy Efficiency

Managing electricity consumption focuses on consumers, or on the demand side of the supply and demand equation. There are many methods to manage consumer demand for electricity. The fundamental approach, with which the Northwest energy industry has much experience, is by improving the efficiency of our energy use. Using energy more *efficiently* means getting the same or more useful work while using less energy. It means that consumers can preserve or enhance their lifestyles and industries can preserve or enhance their production figures, all while paying less for energy.

Using electricity more efficiently achieves three primary objectives.

- Economic savings. Using less electricity saves consumers money. It also extends the life of our generation supplies and transmission and distribution systems by reducing the demands on them and postponing needed investments in new equipment.
- Environmental protection. Reducing consumption of electricity reduces generation of electricity. Although our region is heavily dependent on hydroelectricity, the marginal resource is almost always a fossil fuel power plant, most likely coal or natural gas. This means that each MWh saved displaces between 800 and 2500 pounds of carbon dioxide (CO_2) emissions while reducing emissions of air toxins like sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury.
- Enhanced reliability of the electricity grid.

Efficiency measures can range from unplugging unnecessary light bulbs in vending machines, to modifying industrial processes, to designing commercial buildings that use less electricity while providing improved lighting quality, to introducing energy efficient motors to the marketplace. In the past, least cost planning[3] was a key driver for investing ratepayer funds in energy efficiency. Simply put, it is cheaper to save electricity through efficiency improvements than to construct new generation and expand existing distribution and transmission systems.

Electric utilities and the energy services industry in the state have over two decades of experience capturing cost-effective energy savings for consumers. Some of this ability to use energy more efficiently is evident in statewide data for residential energy consumption. Despite a 22% increase in the average size of a new home (by 400 square feet since 1986[4]), and huge increases in the number of household computers and other electricity-gobbling home electronics, the average household energy consumption in the state has remained flat over the last decade.[5] While many factors contribute to this, developments like instituting the Washington State Energy Code, improvements in efficient window technologies, and the array of energy efficient appliances and compact fluorescent light bulbs are key contributors.

Such developments as the increase in use of telecommunication devices, computers and electronic appliances; the growth in commercial development; and the overall growth in the state present a challenge to Washington's energy planners. Washington's electricity consumption has increased by 9% between 1990 and 1999. We can meet some or the vast majority of this growth with an increase in energy efficiency.

The *Washington State Electricity System Study*[6], developed for the 1999 Legislature, documented a dramatic 73% reduction in collective utility investments in energy efficiency programs from 1993 to 1998. Funding levels dropped from \$155 million in 1993 to \$42 million in 1998. The two primary causes of the drop in both investment and savings achievement in the mid- to late 1990s were; impending restructuring legislation and the accompanying uncertainty as to what treatment utility investments in efficiency would receive in a restructured industry; and the drop in the avoided cost of power.

The tide has turned on both of those issues. The price of purchasing power has been increasing over the last year and restructuring legislation has not had a hearing in Washington's legislature since 1997. That said, stakeholders still watch the national trend toward electricity restructuring and await resolution of the issue in Washington State. Stories of electricity price spikes and higher natural gas prices regularly appear in the media. These same forces that seem to discourage further consideration of restructuring serve to highlight the need for delivering electricity services more energy efficiently.

The tide has not turned quite so dramatically for investments in energy efficiency. Data for the six largest utilities in the state and BPA indicate that investments in energy efficiency have shrunk beyond the 1998 low to $37 million in 1999 and $39 million in 2000. (Over 40% of this investment reflects the work of Seattle City Light which represents 18% of this load.) Investments are projected to rise to $46 million in 2001. Still, this is less than one-third of the 1993 investments. Savings from utility, ratepayer-funded programs are expected to increase from approximately 17 aMW in 1999 to a projected 23 aMW in 2001. (See Table 1.)

Data on electricity efficiency investments for the last three years include half of BPA's past annual investment of approximately $10 million in the NEEA. (This is less than one-tenth of the investment that BPA was making in energy efficiency just in Washington in the mid-1990s.) Additionally, BPA will begin to implement its Conservation and Renewables Rate Discount program in October 2001. The intent of this BPA program is to provide a rate discount for its utility customers who invest in energy efficiency or purchase renewable resources for their customers. This program may leverage an additional 7-8 aMW of savings by Washington utilities in 2002.[7]

The state also has a role in capturing energy savings. For example, the state can adopt procurement guidelines that require agencies and universities to purchase cost-effective energy efficient products and to construct and lease energy efficient buildings. The state can direct resources to the Department of General Administration, which has a very small staff that focuses specifically on delivering energy efficiency assistance to public facility operators at agencies, schools, and community colleges. The state could remedy its energy code amendment process that is failing to capture cost-effective improvements that have been made in building products over the last 8 to 10 years. These improvements are not cutting-edge practices; frequently they are a common construction practice that is simply not reflected in code, and therefore is not captured in all new buildings. For example, updating just the residential window efficiency standard to reflect construction that is current practice throughout most of the Northwest and all of Oregon would save the new homeowner an average of $70 per year in energy bills and would reduce natural gas consumption in the state by 476 thousand therms per year.[8] These are remarkably low-cost savings that the state is not capturing with its current code amendment process.

Politically, consumer interest exists even in rural, conservative parts of the country to support investments in energy efficiency[9]. Economically, a vast resource of cost-effective electricity savings is still available in Washington. This is most readily evident by comparing annual achievement of electricity savings in the state to the Northwest Power Planning Council's assessment of available potential. Seattle City Light, with the most

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000P	2001P
Budget (millions)	$138	$155	$126	$95	$77	$44	$43	$37	$39	$46
Savings (aMW)	70	100	81	N/A	N/A	N/A	N/A	17.7	19.8	22.6

P-Projected

Table 1 Electricity Efficiency Investments and Savings in Washington[10] aggressive energy efficiency plan of any utility in the state, is pursuing a strategy to cost-effectively double its electricity savings achievement. The potential exists for other utilities to achieve similar goals. While Seattle is currently capturing at least seven-tenths of 1% of its load in savings, preliminary indications are that the state's other large utilities are capturing significantly less of their load in savings. In January of 2001, the Northwest Power Planning Council begins to produce a new power plan that will provide an updated resource plan with the electricity savings potential available in the Northwest. Their goal is to complete a draft by January 2002. While this efficiency resource is not boundless, neither is it being fully utilized.

Report on NEEA

In October of 1996, NEEA was jointly funded by the Northwest's investor-owned electric utilities and BPA. NEEA was the first non-profit of its kind nationally with a mission to catalyze its regional marketplace to embrace energy-efficient products and services. NEEA forecasts that its first three years of programs will reduce annual electricity consumption in 2010 by 410 aMW at a total cost to the region of 2.3 ¢ per killowatt hour (kWh).[11] This is enough electricity to offset the construction of more than one natural gas power plant. If all the resource savings – electricity, water, natural gas, etc. – are included in the calculation of benefits, then the electricity saved cost the region less than 1¢ per kWh. This is one-third the cost of new generation. Initially funded for a three-year trial period, NEEA has proven to be successful beyond expectations and is now a model that other regions in the country seek to replicate.

This past spring of 2000, Governor Locke was joined by Governor Kitzhaber, BPA's Administrator, public and private utility executives, and energy stakeholders from Oregon and Washington to celebrate a new funding commitment of $20 million annually for the next five years to the Northwest's Alliance. The setting for this celebration was Siemens Solar Industries' manufacturing plant in Vancouver, Washington, a case study of NEEA's success.

Case Study: Siemens Solar Industries, Vancouver, WA.

Siemens Solar Industries is one of the world's leading makers of solar cells. NEEA provided matching funds to Siemens to implement a project to reduce the electricity used in the energy-intensive process of melting silicon crystals to grow silicon ingots - key components of both solar panels and computer microchips. The near-term goal was to save electricity in this facility and verify the savings due to modifying the furnace technology. NEEA's long-term goal was to demonstrate the success of the furnaces to the ever-expanding microelectronics industry with the goal of having the wafer manufacturers adopt the technology.

Siemens Solar's Vice President shared project results in Vancouver which proved to be great for business, great for the environment, and very helpful in reducing electricity distribution constraints in Clark PUDs industrial service territory. The NEEA-Siemens project reduced power consumption by 51% and Argon gas consumption by 85% for each kilogram of ingot produced, and increased useful ingot yield by more than 20%. Further, the solar cells made with the new silicon ingots produce 5% more electricity than their predecessors, and now cost 5% less. Currently, one wafer manufacturer is testing the furnace modification, and Siemens is expanding its operation in Vancouver.

NEEA's projects are diverse. They include all sectors, and range from bringing front-loading resource efficient clothes washers and a new generation of compact fluorescent bulbs to Washington's retail stores, to increasing the use of variable speed fans in our refrigerated fruit warehouses. Projects also include: financially supporting weather stations that provide essential data to farmers scheduling irrigation; verifying the effectiveness of new technologies that reduce energy consumption at and extend the capacity of sewage waste treatment plants; and assisting the start-up of a Washington company that is introducing new energy efficient motor coupling technologies in the marketplace.

Funding NEEA is a powerful investment in Washington's future as it reduces energy consumption while frequently enhancing, rather than simply maintaining, business practices or lifestyles. NEEA programs will save the Northwest from emitting 1.6 million tons of carbon dioxide by 2010—the equivalent of taking 25,000 cars off the road for good—at costs that are lower than buying market power or building new generation.

Over a 10-year period, NEEA's initial investment of $65 million leverages electricity savings valued at $792 million to the region. Roughly half of these regional savings accrue to Washington's residents, businesses, and industries.

Several of Washington's large public utilities are currently budgeting to provide direct financial support to NEEA later in 2001.

Load Management

Because of our vast system of hydroelectric dams and reservoirs, the Northwest has not historically been capacity constrained. Hydroelectric dams have tremendous peaking capability, which means there is nearly always another kWh of energy available to meet the highest peak demands on the system, and it costs little more to produce that extra kWh. More recently, however, growth in consumer demand and the relatively small amount of new resources developed in the region have shifted the Northwest into an electricity market that is now capacity constrained.

Many regions of the country have faced capacity constraints for decades, and have more experience in operating programs to manage consumer demand for power when the power system has reached its limits. The primary motivations for managing peak periods of consumer power consumption vary. Benefits include avoiding the purchase of power during extreme price spikes, enhancing reliability during periods of extreme weather events, extending the life of existing distribution and transmission systems, postponing the need for constructing new peaking generation, and keeping businesses that are exposed to market prices operating. (In Washington, only some industries, and no households, pay market prices for power.)

There are a variety of terms used to describe managing consumers' electricity consumption and it is useful to clarify a few of them. **Load** refers to the amount of power consumers use; in this subsection, power refers specifically to electricity. **Load demand** is comparable to consumer demand for power. **Peak load** or **peak load demand** refers to a time period – usually hours of a day or a season of the year – when consumers are demanding noticeably more electricity than at other average load periods.

Northwest Load Patterns

Figures 3, 4, and 5 indicate periods of time when Northwest consumers use the greatest amounts of electricity; these are known as peak load periods. Figure 3 shows the seasonal peaks in demand for electricity. December and January are clearly the two months when consumers in the Northwest use the greatest amounts of electricity. The darker bars indicating peak energy demand in a month are taller than the average energy demand each month. The load factor on the right-hand side of the chart is a reference to the percentage difference between peak demand and average demand. The differential between the peaks and the averages are the most extreme in the winter, when as a region we have the lowest load factor. (A high percentage load factor means that the demand for power is fairly constant, such as an industry that is operating seven days a week, 24 hours per day.) This graph indicates that the winter season will place the greatest average demand and the greatest peak demand on Northwest resources.

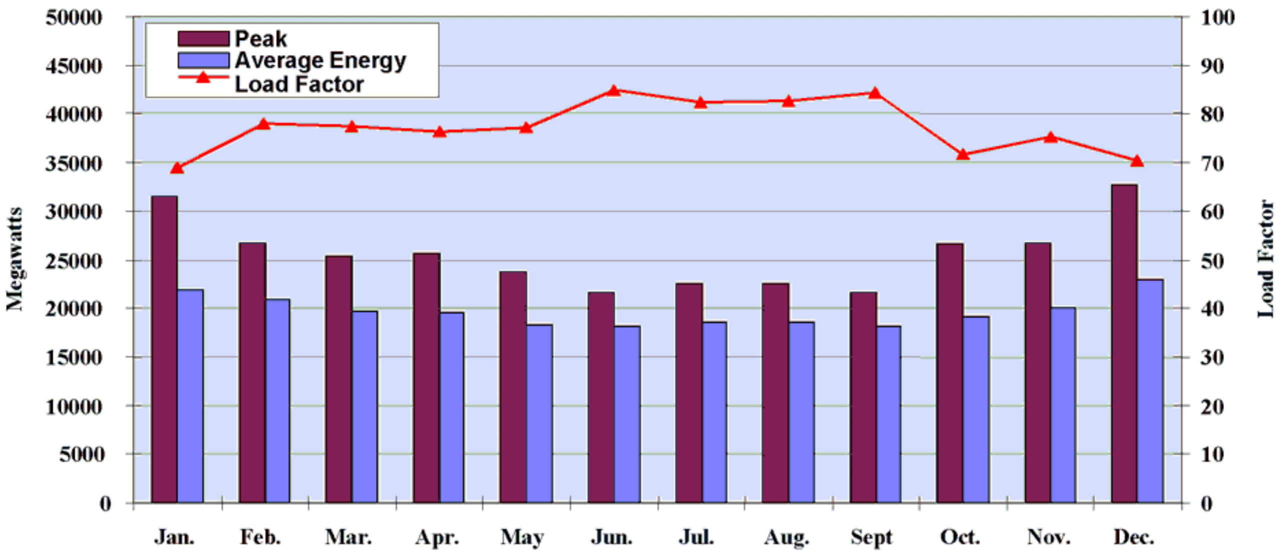

Figure 3 Seasonal Northwest Load Patterns 1995

Source: NWPPC, 4th Northwest Power Plan, Appendix D, Economic and Demand Forecasts, 1996

Peak load management programs aim to reduce the differential between average demands for electricity and peak demands for electricity. Programs may be described as reducing, managing, or shifting loads when demand is the highest. Their intent is to reduce the differential between the dark, peak bars and the average, light bars. Figure 4 provides an average winter day load curve. A winter load management program might target flattening the daily curve at 7 and 8 a.m. and at 6 p.m. In general, load management programs are implemented to reduce peak loads when the value of the savings is the highest.

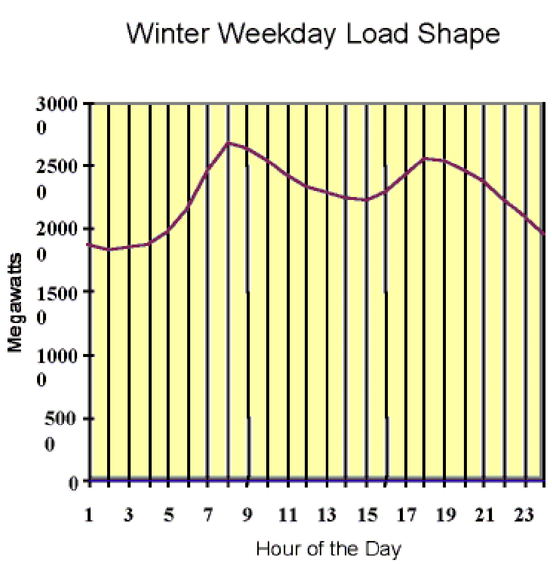

Figure 4

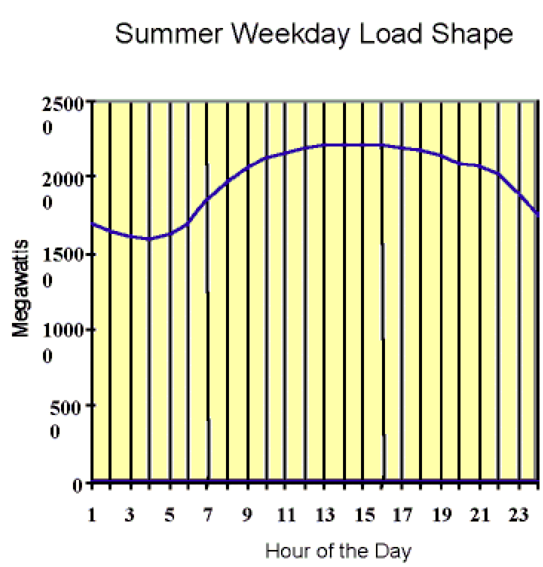

Figure 5

Figures 4 & 5: Typical Winter and Summer Weekday Northwest Load Shapes

Source: NWPPC, 4th Northwest Power Plan, 1996

There is an important distinction between energy efficiency and load management programs. The savings from energy efficiency programs always reduce load. Additionally, energy efficiency measures maintain or even enhance the level of energy service that a customer receives. Peak load management programs either curtail energy use, and thus lower the level of energy service or amenity that the customer was receiving through its electricity consumption, or they typically increase energy use, but shift the consumption to a different, non-peak time of the day or they rely on the use of backup generation. Peak load management programs do not generally achieve any electricity savings. For example, commercial buildings could make large blocks of ice during non-peak evening hours, and then circulate air over these ice blocks in the daytime peak periods to cool the building. In this example, a comparable or large amount of energy is used to provide air conditioning in a commercial building, however the energy used for 'cooling' is consumed at night when it places less strain on the system. In contrast, energy efficiency programs not only reduce load, but also can be designed to save electricity at peak periods of the day or year. For example, energy code improvements that reduce the heating or cooling load for a new residential or commercial building reduce both consumption of electricity and peak demands for power.

Having the ability to manage peak power demands is particularly critical to preserving a reliable electricity grid. Just this December, demand on the electricity system exceeded supply during a cold snap. It is extremely valuable to manage peak demand in the Northwest during periods of high loads driven by extreme weather events that coincide with periods of constrained generation such as poor hydropower conditions or unplanned generator outages. Severe winter peaks are associated with concerns for power outages due to limited power supplies or transmission capacity. Regional stakeholders work collectively on this issue in establishing winter readiness plans. (See Chapter 4.) In these cases, managing weather-driven peaks serves to enhance the electricity system's reliability.

In the absence of load management programs, generation supplies are needed to meet these peak periods of electricity demand. National research shows that in the New England Power Pool, 9% of the generation exists to meet peak loads 1% of the hours during approximately two weeks per year. In Florida, data indicates 15% of the generation is operated to meet peak loads 1% of the time.[12] Reducing the differential between the peaks and the average energy consumed has the benefit of reducing the need to pay for and build rarely used peaking generators.

The market price of power in the Northwest in any given hour is clearly influenced by market events throughout the Western Interconnection, including California. In recent years, extremely high demand during heat waves in California and the Southwest has led to rapid increases in the hourly price for power on the California Power Exchange (PX), sometimes to as high as $750 per MWh (or more than 11 times the highest retail rates for electricity in Washington). These price spike events are both the most expensive times to purchase wholesale electricity, as well as the most lucrative times to sell excess wholesale electricity. Consequently, any electricity saved or unconsumed during these peaks has a higher market value than during other hours of the day or times of year. While Washington utilities have traditionally focused on meeting peak demands during the winter heating season, the dynamics of West Coast power markets mean that demand reduction is most valuable when the power system is most constrained. This may be during extreme weather and generator outage events in the winter or summer. (See Chapter 1, Section A.)

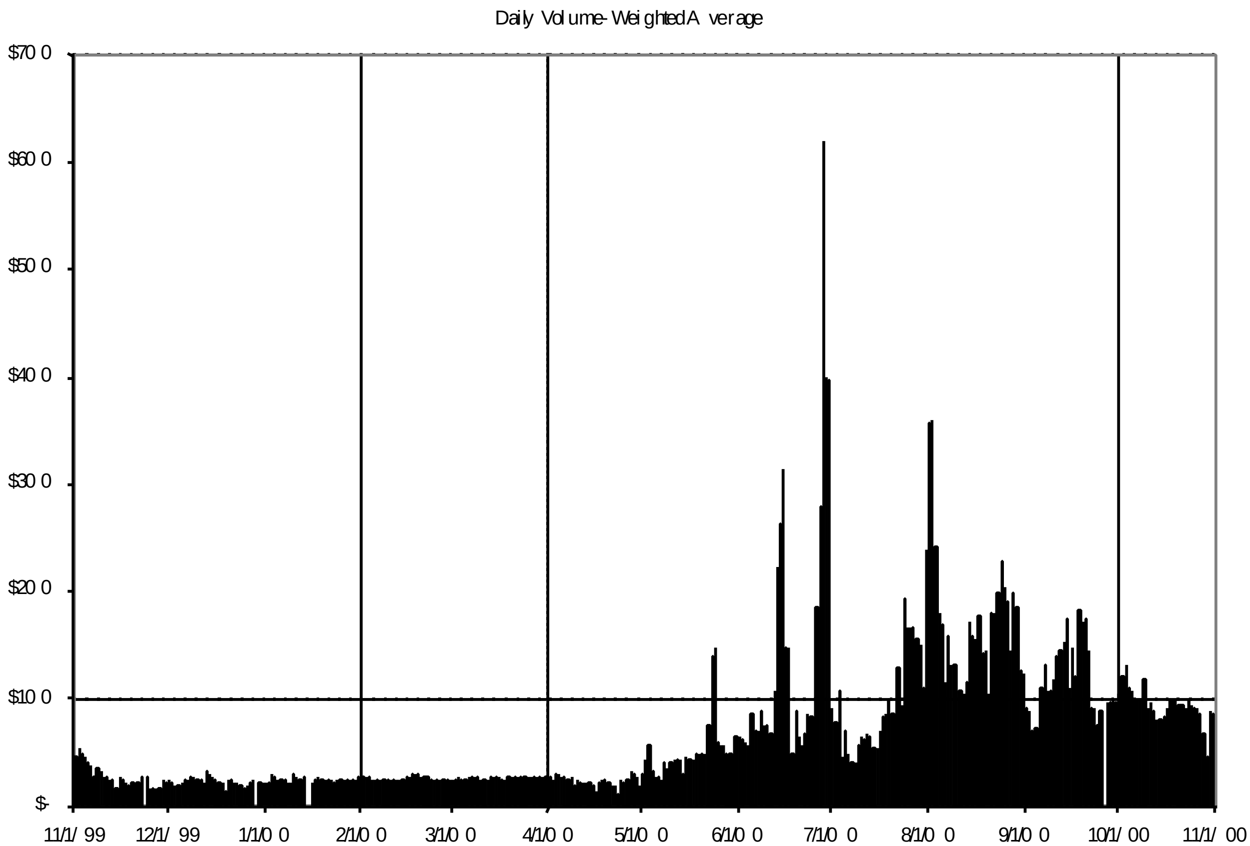

Figure 6 Dow Jones Price Index Power Prices at Mid-C, 11/1/99 - 10/31/00

Source: Dow Jones & Company

Price volatility in wholesale power markets has been especially severe during the second half of 2000. Figures 6 and 7 demonstrate this extreme volatility. Figure 6 presents daily average prices paid for power at the Mid-Columbia (Mid-C) trading hub during a period from November 1999 to October 2000. The Dow Jones Mid-C Index reached a peak of $618 on June 28, about 10 times the highest retail rates in Washington. This December, index prices reached over $4,000 per MWh for much needed power during the cold snap.[13]

Figure 7 presents hourly prices in the day-ahead California PX for an example month of July 2000. There is no hourly market index in the Northwest, but utilities in California are required to purchase the majority of the power they deliver to retail customers in the PX markets, and many companies in the Northwest sell power hourly at prices that are pegged to the PX prices.

Figure 7 gives an indication of the differences in the value of power from one hour to the next. Even during the relatively stable days early in the month, the value of power can vary from $25-30 per MWh during the night to $80-100 per MWh during peak hours in the late afternoon. The last ten days of July saw extreme volatility, with prices frequently approaching the actual $500 cap[14].

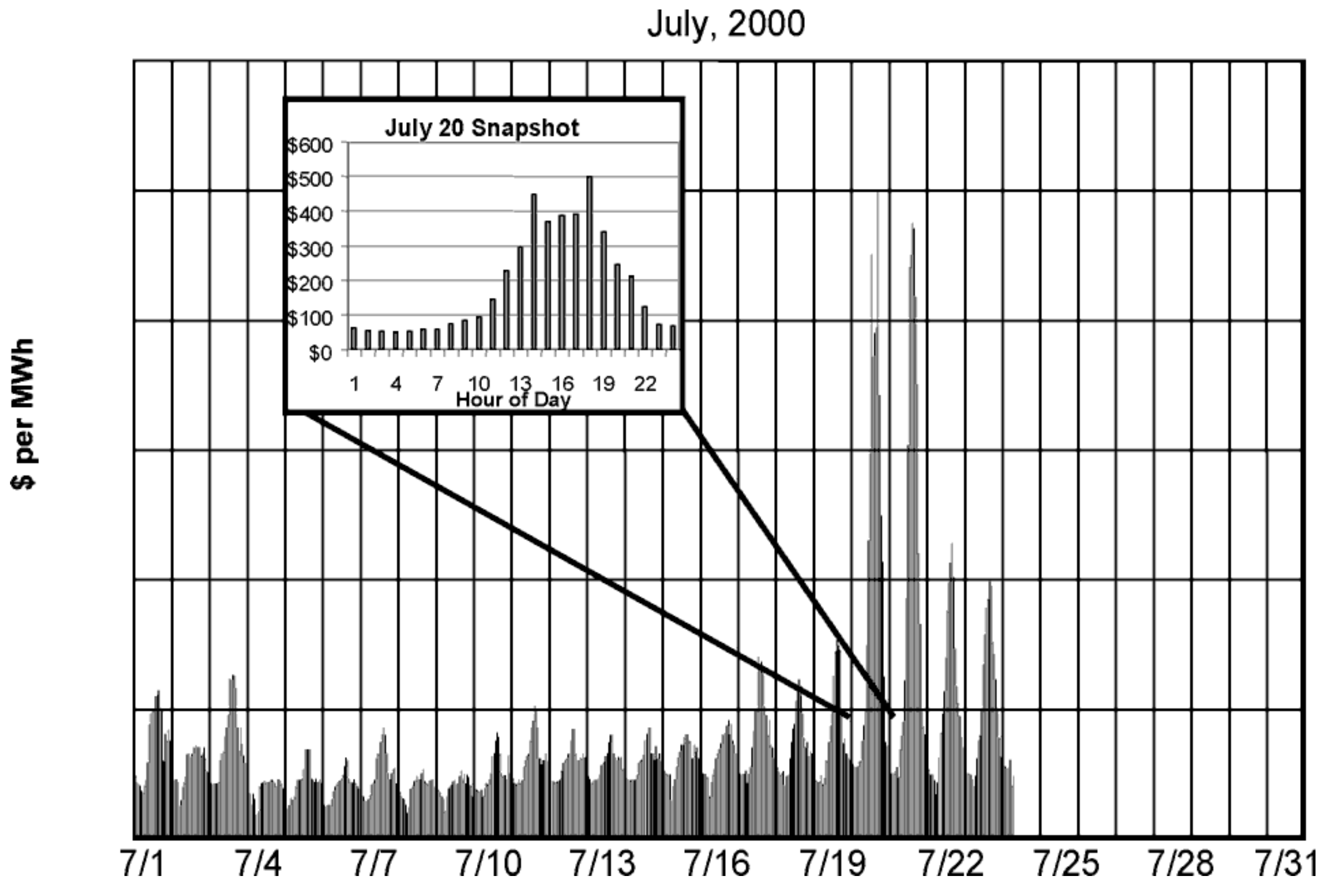

Figure 7 Cal PX Hourly Unconstrained Market Clearing Prices, July 2000

Source: California PX

The trends depicted in these figures contain two lessons for encouraging demand-responsiveness in the Northwest. First, load-management programs will have their highest value during times of extended power supply tightness. Power supplies were short throughout the summer of 2000, which meant that a variety of events such as generator outages that would normally pass unnoticed tended to spark significant price increases. Programs that take a longer-term approach to load management, such as increased energy conservation or backup generation, may be the best way to approach these types of problems. However, the second lesson is that intra-day price differentials may be significant enough to make demand responsiveness val-uable even in relatively less volatile periods: load shifting programs over the course of any single day could have economic value to the customer and to its electricity provider.

A number of programs are being instituted throughout the country that seek to engage retail customers in responding to high market prices during times of peak demand. The section below describes some of these programs and provides an update on what policy-makers are learning from these programs.

Strategies for Managing Peak Loads

Strategies for managing peak loads fall into the following general categories:

1) Direct load control programs: either local utilities or energy service providers implement these programs. The utility or service provider installs control technology in the residence, business, or industry and has the ability to manage a specific load, such as dimming a building's lighting or cycling off a home's water heater, through the control mechanism. The load reduction from these programs is reliable and predictable. Automatic meter readers,

while not mandatory, can verify that the control equipment is functioning and is reducing customers' loads.

2) Interruptible rates: Customers who were willing to exchange lower rates for the possibility of having their utility interrupt or curtail their electricity service in an emergency may have signed up for interruptible electricity rates. These were typically industrial or large institutional customers. Historically, these customers were rarely, if ever interrupted. However, anecdotal information indicates that industries in California were interrupted approximately thirty times over the past year. This December, Puget Sound Energy (PSE) directed schools on interruptible rates in its service territory to reduce electricity con-sumption during the month's cold snap.

3) Bidding for voluntary load shifting: These are newer programs in which a power aggregator or retail energy provider offers to pay large customers to reduce their loads. These are also called power buyback programs. The customer can decide whether the price offered is adequate for them to shed load. These programs have minimum load reduction requirements; e.g., 500 to 1000 kilowatts, and require that customers agree to shed load for a minimum amount of time – typically one hour. As power supplies get tight, these prices get higher.

4) Contracting for voluntary load shifting: This is similar to the program above except that customers sign a contract agreeing to a pre-determined price at which they commit to shed a specified amount of load.

5) Distributed Generation: Operating back-up generation is what frequently permits industrial and large institutional customers to shed load in any peak load management program. Sup-elemental power can feed directly into the grid, or backup generation can enable a consumer to reduce load on their retail energy provider. Most ex-isting backup generation operates on diesel fuel and operating these units results in significant increases in air emissions. Guidelines need to be established in conjunction with air quality authorities to operate backup generation as part of a load man-agement strategy.

Included here is an overview of California's Assembly Bill 970 that includes key provisions to reduce peak electricity load in California and a sample of the types existing of load management programs. Also detailed are load management concepts that integrate smart meters, consumer control technologies, and power pricing strategies that may provide tools in the near future for managing peak loads.

California Assembly Bill 970 (AB 970)

In response to the extreme price events described above, and to general growth in electricity demand accompanied by a lag in construction of generation, the California As-sembly enacted and the Governor of California signed AB 970, the *California Energy Security and Reliability Act of 2000*, into law in early September 2000.

"The purpose of this act is to provide a balanced response to the electricity problems facing the state that will result in significant new investments in new and environmentally superior electricity generation, while also making significant new investments in con-servation and demand-side management programs in order to meet the energy needs of the state for the next several years.[15]"

In San Francisco, the immediate costs and risks of electricity price spikes were borne by the utility. In San Diego, consumers bore the risks and price spikes that were immediately averaged into their very unaffordable rates. These events underscored the need for meaningful energy policies regarding real-time pricing, load management, and utilities' roles in each. California's response to these events that threatened the reliability and affordability of their electricity system went beyond "build more generation." It addressed siting policies and the construction of new generation as well as achieving greater electricity savings and operating programs to manage electricity loads.

Among the strategies mandated in AB 970, a budget of $50 million was allocated to state government with an assignment to reduce load demand by 175 to 200 average megawatts (aMW) by June 1, 2001. This is a remarkable statewide effort that will focus particular applications in transmission-constrained San Diego and San Francisco. This one-time load reduction budget is separate from, and in addition to, the funds that the California Assembly directed utilities to invest in energy efficiency, renewable resource development, and low-income weatherization. These separate investments in California's electricity system exceed $200 million annually and have been extended for ten years. This $200 million annual investment also serves to diversify California's power supply with renewables and to reduce electricity consumption through efficiency measures.

The following provides the initial, though flexible, allocation of funds for load reduction that California wants to have in place by June 2001. The majority of the programs focus on shifting power consumption to non-peak periods; the traffic light program reduces load and electricity consumption; and some funds increase the development of renewable resources.

$10 million	Conversion of light-emitting diode (LED) traffic signals.
$10 million	Price responsive heating, ventilation, air-conditioning and lighting systems. The goal here is to leverage the refinement and installation of needed metering and control technologies and software that enable commercial building managers to respond to information on price spikes or energy emergencies that may be sent by the independent system operator.
$10 million	Cool communities: includes painting rooftops white to reflect heat in the peak summer season and planting shade trees.
$5.5 million	Energy efficiency improvements in public universities and other state facilities. This includes improving energy efficiency in these facilities and developing policies and plans that enable public facilities to reduce loads during energy emergencies or energy price spikes.
$5 million	Water and wastewater treatment pump and related equipment retrofits.
$8 million	Development of renewable energy resources for both on-site distributed energy development and for commercial scale projects, and any load reduction strategies that do not fit another category.
$1.5 million	Consulting services as needed.

Dynamic Pricing

The wholesale electricity market faces large swings in prices from hour to hour as described above. Washington's retail consumers do not experience these real-time prices immediately (with the exception of some large industrial customers with market-indexed tariffs or special contracts). Instead, customers pay an average price for power that reflects their utility's strategies for serving load; whether it includes the costs of constructing peaking generators or includes the costs of market power purchases complete with price spikes. The concept of dynamic pricing is to connect the variations in the wholesale price of electricity to those retail customers with the willingness and ability to either self-manage their electricity use or to have their energy service provider manage it for them. Dynamic pricing is most frequently discussed in the context of competitive markets and is a variation of "bidding for voluntary load reductions at market prices" described above. However, there may be applications in regulated markets as well. The goal is to have these customers, representing enough load, respond by shifting or reducing demand for electricity during the periods of extreme demand in order to reduce power prices for all purchasers at that period. Analysis suggests that "a mere 5% market share with a 0.1 elasticity of demand facing spot prices would have reduced a price spike by 40%."[16] Figure 8 demonstrates that, with some exceptions, prices in the California PX day-ahead do not begin to spike until demand reaches some 27,000 MWs.

This does not mean it is useful for all customers to experience market price signals. Most customers may have no ability to manage their loads. In addition, the shape of the electricity supply/price curve is primarily flat in many hours. This means that power prices are steady and provide little incentive or need for consumers to manage load. The value of managing loads is highest during those periods of high consumer demand and constrained supply when the price of power increases rapidly.

San Diego customers were not experiencing dynamic pricing this past summer. The high prices were indeed passed onto the consumers. However, the hourly electricity prices were overlaid with the average load profile of residential consumers to create a monthly bill. Residential customers did not have real-time meters and therefore customers could not benefit by operating electrical equipment at night when demand and prices were lower. The only option consumers had to manage their loads in response to such signals was to turn-off equipment, such as air conditioning for days at a time.

In a well-designed dynamic pricing regime, energy service providers or utilities would negotiate multi-purpose contracts with voluntary customers to purchase electricity for the customer while simultaneously managing the consumer's energy use and operating their load to respond to price signals. For example, the utility or energy service provider may have controls to operate the customer's backup generator, or cycling-off hundreds or thousands of residential hot water heaters for an hour, or increasing the air conditioning thermostat in industrial or commercial buildings.

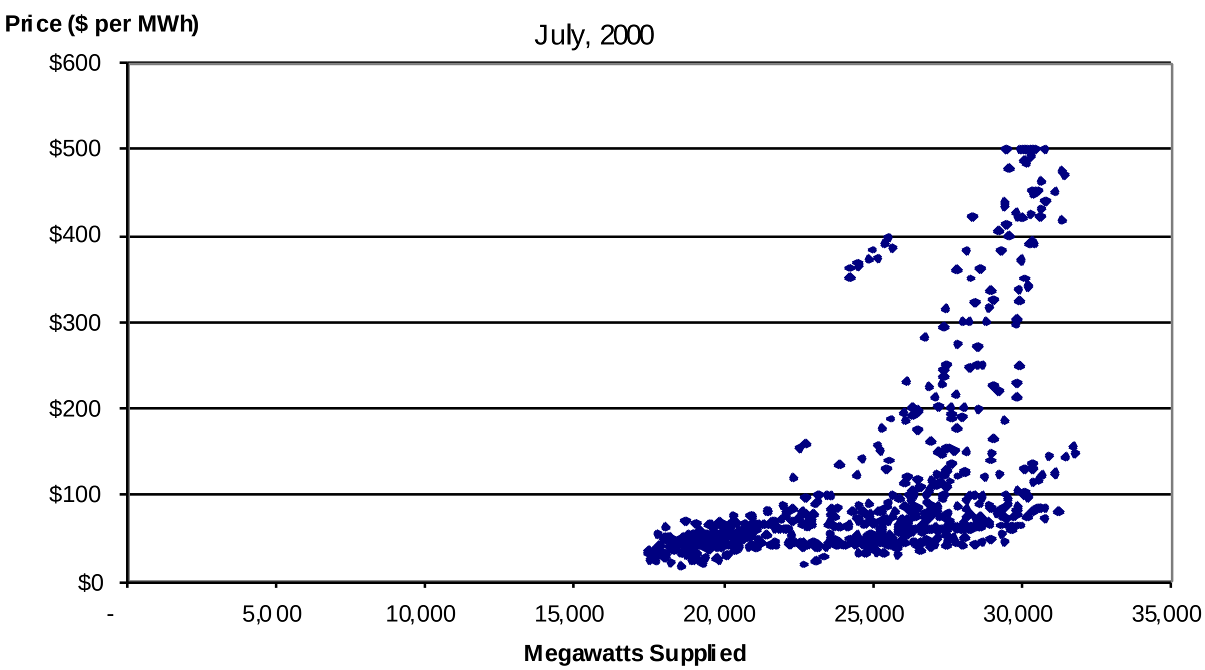

Figure 8 Supply Curve in Cal PX Day-Ahead Market

Source: California PX

Real-time power price signals can create opportunities for consumers to participate in load management programs if the necessary infrastructure exists such as real-time meters (meters that measure electricity consumption instantaneously or every 15 minutes), energy management software, and the appropriate load control technologies. However, real-time pricing may expose customers to market electricity prices without any choice of provider and without the necessary capability to manage their consumption. Participation has to be voluntary to avoid risk-averse customers or customers with little or no ability to respond to real-time prices having to pay volatile electricity prices.

Any use of dynamic pricing, particularly in a monopoly environment should be directed to:

- businesses, industries, or households that either have or can be readily retrofitted with the necessary load control equipment;
- customers that are willing to participate in utility sponsored programs that assist with, provide consultants, or actually manage customer loads and enable the customer to benefit from lower-priced power at non-peak periods;
- customers that provide the electricity system with the greatest peak reduction at the lowest total cost – including installation of control technology.

Participating customers' willingness to respond to prices is influenced by their ability, or that of their energy provider, to intelligently use load management technologies such as control systems, their access to flexible end-use technologies (thermal storage or back-up generation), and their ability to adopt flexible production schedules or to reschedule building operations.[17]

In Washington, where many, but not all, utilities are exposed to spot market prices for only a minority of their power purchases, it may be useful to provide some shared incentive program that encourages a utility to implement load management programs in order to reduce system peak demand and to better utilize existing resources and distribution systems.

Public Appeals to Conserve

In other regions of the country, there are occasionally public appeals to turn off electrical equipment due to the risk of a blackout. These types of public service announcement efforts – frequently communicated over radio stations – have succeeded in temporarily reducing load by as much as 10% according to anecdotal data. The goal of utilities and government agencies is to avoid relying on this tactic repeatedly, but to realize that it is an effective tool for immediate and temporary reduction in electrical load. The Northeast has extensive experience with this public appeal approach.

The Northwest had a rare occasion to use a public appeal campaign during a very serious drought that lasted at least eight months in 1977. Washington and Oregon and their utilities launched a huge public appeal to consumers to reduce energy usage. Governor Dixie Lee Ray turned off the lights in the Capitol Dome as an example, and Oregon banned lighting for outdoor advertising in public rights of way by governor executive order. There were daily reminders to restrict consumption. As a result of this campaign the state's largest electric utility reported a 5% reduction in *total energy* consumed for the *year*. This was not a peak load issue; this was an energy issue as there was little water behind the dams. The savings were not simply capacity savings but total energy savings.

More recently, the request this December by utilities and Washington's Governor to use less electricity during the cold snap reduced short-term demand by approximately 3-4%.

Eugene Water and Electric Board's Response to December 11th Cold Snap

In Oregon, Eugene Water and Electric Board achieved a 14 MW load reduction on December 11, 2000. Based on Energy Information Administration data, that is about 5% of their load. Eugene Electric's industrial key account representatives had been preparing for this type of event and were able to identify, in advance of the cold weather, load shedding or generation backup opportunities with their two to three dozen largest customers. They estimate that half the 14 MW reduction was achieved with the use of customer backup generation and half by load shedding. Eugene Electric paid their customers three-quarters of the market price not to exceed $500 per MWh. By knowing their industries, Eugene's key account representatives could readily identify customers with inefficient generators that normally sat unused, or customers with loads that were "non-critical" in any given day. For example, one plant shut down a huge card-board recycling machine for the day, while one mill shut down two days early to sharpen their blades off-schedule in exchange for the payment.

Eugene Electric also ran a media campaign that asked customers to lower their therm-ostats, turn-off unnecessary appliances, not use Christmas lights until after 8 p.m., and turn their water heaters down to 120 degrees Fahrenheit. They utilized stories in the news, public service announcements, and television news segments.

Bidding Voluntary Load Reduction

BPA's Programs

BPA purchases power from the wholesale market, in which there are periods of price spikes; and yet charges its wholesale and retail preference customers fixed prices for electricity that do not vary as market prices vary. Additionally, there are episodes in the winter when the Northwest is physically con-strained in its ability to meet extreme demands for power. In response to these two factors, BPA is currently recruiting participants to participate in a voluntary load displacement program. Their target is to sign up 300 aMW of load by mid-December, increasing to 800 aMW of load by December 2001.[18]

Participants will be offered the opportunity to bid in an electronic auction to determine the price per kWh at which they will curtail load. Minimally, participants must be able to shed one MW of load for one hour. By early November 2000 BPA had four customers representing approximately 150 MWs of load registered. The participants range from industrial plants located in service territories of BPA's customers, to industries served directly by BPA, to a small Oregon utility prepared to curtail load. The utility has radio-controlled equipment already installed in residences that will allow the utility to cycle off hot water heaters for an hour at a time. Comparable programs are in the design or early implementation phase in a number of regions in the country.

Portland General Electric's Electricity Exchange

Effective July 2000, Portland General Electric initiated its Electricity Exchange Rider Pilot. The goal of the voluntary program was to buy back power from large customers that had the ability to curtail load. The utility sends large customers a one or more day-ahead price signal to which participating customers can choose to respond by reducing at least one MW of load for a minimum of one hour, for up to 16 hours per day. Portland General Electric modified the program slightly in late fall 2000. The utility now has the flexibility to select when to announce a voluntary load-shedding event, rather than announcing one based on a specific California PX price. The utility financially settles with their load-shedding customers by paying half of the California Independent System Operator's real time price for Northern California. This program has proven to be beneficial to Portland General's shareholders and ratepayers. Approximately ten large customers are participating with some regularity.[19] The pro-gram resulted in 150 MW of peak load reduction during events in December 2000.[20]

Puget Sound Energy Load Management Pilots

PSE has replaced nearly one million big, old glass meters with automatic meter readers (AMRs) in their service territory over the past several years. While traditionally meters are read monthly or bimonthly and provide only a total amount of energy consumed during the month, AMRs rely on radio devices to take measurements of consumer energy consumption in real-time. PSE is initiating a pilot program this winter using these meters to track time-of-day electricity consumption for

400,000 residential and commercial customers. Their goal is to see if providing customers with hourly consumption data, overlaid with simplified information on market power prices during four periods of the day, will stimulate customers to voluntarily shift their electricity consumption to another time of day.

Additionally, PSE implemented a small pilot program in 104 homes in Kent during February through April 2000, entitled, "Home Comfort Control Pilot." The purpose was to test the utility's ability to manage load using thermostat setbacks. The majority of the homes were natural gas heated, which are not the real target for near-term electric load management programs. Still, some of the lessons learned were fuel-neutral.

During an 8-10 week period volunteer households experienced 45 random two-hour episodes at which time their thermostats experienced either 2 or 4-degree temperature setbacks. Volunteers could override the setbacks and have full heat if desired. Pilot partners provided or installed programmable thermostats, wireless communication, and energy management software.[21]

The conclusions from the pilot indicate that the two-way communication system performed reliably; 95% of the volunteers would participate again; and 75% indicated a willingness to experience 30 setbacks per year. Incentives to participate in the pilot included a free programmable thermostat and $100.

Utility Load Control Programs

Wisconsin Electric implemented a peak load management program in 1991. The utility installed radio receivers in residences and wired them to the thermostats in order to reduce air conditioning load. This program did not cut off the air conditioning; instead it adjusted the thermostat control by signaling that the house was cooler. The utility could invoke the controls during five to ten days per summer. While they implemented this control technology seven times in 1999, they didn't use it all in the milder summer of 2000. The utility has three program and payment options that include giving a $40 per year customer credit for participating for up to four hours versus a $12 annual credit for allowing the utility to cycle the air conditioner off for 15 minutes every hour. They currently have 25,000 customers participating and can reduce load by 50 MWs. The program was marketed to consumers as a reliability program and is only operated at times of supply constraints, not for the utility to avoid purchasing power during price spikes.[22]

Similar load control programs for a variety of appliances that contribute to peak loads have been in place in the Northeast and Southeast for years. Many of these programs were discontinued as states restructured their electricity industry. These programs need communication and control technology, but do not require real-time meters. Well run load control programs have been favorably well-received by customers. One 1995 study in Grand Rapids, Michigan measured the indoor temperature increase of 200 households participating in a load control program of over 1,000 households, shutting off their air conditioning for up to four hours. The average temperature rise was never greater than 1.8 degrees F. The maximum temperature rise was 2.8 degrees F.[23]

Both the Los Angeles Department of Water and Power and Sacramento Municipal Utility District demonstrated thermostat control programs in their own utility buildings last summer in the hopes of operating full scale programs in the summer of 2001. Los Angeles Power raised the thermostat settings by two degrees between noon and 6 p.m. in two buildings totaling 850,000 square feet. The project was estimated to reduce load by 300 kilowatts and it received almost no complaints from the occupants. Sacramento's demonstration dimmed the lights by 30% and raised the thermostat by four degrees in one of their commercial buildings. They observed an average peak load reduction of 30%. Employees did not report noticing any differences in their work environment. Many variables can effect these results and it is difficult to establish firm savings numbers.[24]

Wisconsin's Electric Dollars for Power & Power Market Incentives

Wisconsin Electric designed two load management programs immediately prior to the summer of 2000. They have not implemented these programs yet due to the mild summer that year. "Dollars for Power" is a voluntary load reduction program. Customer's need a demand meter and the ability to reduce their load by 50 kW. The utility maintains a reference load shape and reimburses the customer when they measure a drop in load, commensurate with their target. Participants can select one of three prices: $.40, $.80, or $1.25 per kWh. When wholesale market prices reach these thresholds, the utility contacts the customer, and the customer sheds load. Some participating customers have backup generation. The utility recruited 100 MWs of load participation from approximately 100 customers.

The "Power Market Incentives" program requires that a customer can minimally shed 500 kilowatts. Wisconsin Electric activates this program the day before they need the customer to shed load. The customer receives 100% of the wholesale market price in exchange for shedding load. Their recruitment experience suggests that large customers will not shed load for less than $300 per MWh.[25]

New England Independent System Operator

Independent System Operators (ISOs) are starting to implement peak load management programs that include operating backup generation and purchasing power capacity. The ISO's primary responsibility is to operate the transmission system and an ancillary service market. In New England, the ISO is testing a pilot program this winter in preparation for full implementation in the summer of 2001. The goal in New England is to maintain the reliability of the regional electricity grid at a lower cost. The New England ISO target is to have 300–600 MWh of load participating in their program that would enable the ISO to communicate via the Internet with the participant and obtain load shedding within ten minutes. The ISO will contract with customer aggregators or local utilities to achieve this load reduction capability. In turn, this will permit the ISO to reduce their Federal Energy Regulatory Commission required "spinning reserves" (their system's power reserves). Additionally, the communication and metering equipment installed for the purpose of enhancing system reliability and lowering the cost of this reliability will also permit these customers to benefit from reducing load during future market-driven price spikes.[26]

The California ISO is currently investigating its opportunities for implementing load management projects.

Smart Meters and Communication Software

Smart meters refer generally to meters that have more technological capabilities than the old glass meters that simply measured kWh energy consumption. This new generation of meters can receive Internet e-mail messages, track instantaneous energy demand, remember the moment of peak demand, track energy consumption in minute or hourly intervals, provide power quality monitoring, provide power outage detection, provide frequent two-way communication between the meter and the power provider, enable a customer to receive real-time prices, and send signals to shed non-critical loads.

This meter technology can be installed to work in cooperation with energy management software and load control technologies to enable consumers or utilities to better manage their load consumption. While the utility sponsored load control programs of the past did not rely on this advanced metering technology, the advent of this technology does create new opportunities for energy service providers and customers to manage energy consumption in response to price spikes or incentive programs to manage system reliability. Some new residential developments are installing electronic control systems for appliances in homes that may lend themselves to load management programs. Many commercial and industrial customers already have energy management systems installed in their buildings; installation of communication software may enable some of these customers to respond to power market signals or incentive programs.

The Swedes are demonstrating a new role for smart meters in the future “smart house.” Electrolux Incorporated, a major international appliance manufacturer based in Sweden, is offering 7,000 households on the Swedish island of Gotland free energy- and water-efficient front-loading clothes washers. These homes are wired with smart meters that will count the number of washloads done per household. Electrolux will charge the customers per each washload for the use of the Electrolux clotheswashers. Consumers avoid purchasing a new clothes washer, and Electrolux guarantees service on the equipment, promises to replace the units in 4-5 years or after 1,000 washers, and recoups the price of their product (or more) with their fee per washload. Electrolux is selling clean clothes, not clothes washers. This provides a view into marketing opportunities still to come.

Conclusions

There are extensive and untapped opportunities for using electricity more efficiently in Washington State. Energy efficiency, by reducing demand for electricity, contributes to system reliability, primarily in terms of supply adequacy. Any federal or state utility reliability bill or restructuring bill should include provisions to strengthen rather than allow the continued erosion of funding devoted to energy efficiency programs.[27] Utilities and government need to reinvigorate their efforts to realize these savings. The rewards are increased electricity grid reliability, lower-cost energy services, extended life of existing transmission and distribution systems, lowered reliance on additional natural gas generators, and the reduction of CO_2 emissions into our atmosphere.

Managing our peak loads is an untried tool for many in the Northwest energy community. The benefits of actively exploring and pursuing load management opportunities include increasing the reliability of our power system, reducing electricity wholesale price spikes, avoiding the use of dirty diesel backup generators, and avoiding the cost and construction of generators designed solely as peak power providers.

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1 The Green Book, p. 7, Northwest Power Planning Council. February 1996.

2 Washington State Electricity System Study, Washington Utilities and Transportation Commission, and the Washington Department of Community, Trade and Economic Development p. 9-6, December 1998.

3 WAC 480-100-251. The least cost planning rule adopted by the WUTC in 1987 requires investor-owned electric utilities to evaluate energy efficiency and supply-side investments on an equivalent basis and to select the lowest-cost way of meeting demand.

4 Baylon, David, S. Borrelli, and M. Kennedy, “Baseline Characteristics of the Residential Sector in Idaho, Montana, Oregon and Washington.” February 2000.

5 See Chapter 6, figures 9 and 10.

6 Washington State Electricity System Study, Washington Utilities and Transportation Commission, and the Washington Department of Community, Trade and Economic Development, Chapter 9. December, 1998.

7 Savings estimate based on OTED’s analysis of reasonably optimistic results of BPA’s Conservation and Renewables Rate Discount program if utilities choose to invest heavily in efficiency. Additional information on the rate discount is available on the BPA website, http://www.bpa.gov/Energy/N/C8R.htm

8 Comments submitted by Department of Community, Trade and Economic Development for Code Rulemaking process, 10/12/2000.

9 Roberson, Mark, “What Do Consumers Value: A Report by Central and South West Services Inc., on Deliberative Polls at Central Power and Light, West Texas Utilities, Southwester Electric Power Company.” Presented to the National Association of Regulatory Commissioners.

10 Investment data for 1992 through 1998 represents data from fifteen utilities in Washington & BPA collected for 1998 Washington State Electricity System Study. This study did not collect first year savings data from utilities. Savings data for 1992, 1993, and 1994 were collected by the Northwest Power Planning Council for the 1996 Green Book; this reflects data from the state’s 6 largest utilities and BPA. All savings data and investment data for 1999 through 2001 represents data from state’s six largest utilities & BPA collected for this report. Year 2000 and 2001 data are projected. Investment figures have not been adjusted for inflation. Anecdotal information suggests that smaller utilities are capturing an additional average megawatt of savings in the year 2000.

11 “The 1999 Alliance Cost-Effectiveness and Savings Information.”

[12] Analysis by the Regulatory Assistance Project. See http://www.rapmaine.org

[13] www.energyonline.com

[14] The California PX did not have an official price cap, but prices were constrained by the existence of a $500 price cpa in the real-time imbalance market operated by the California Independent System Operator.

[15] Assembly Bill 970, California Energy Security and Reliability Act of 2000, section 2.

[16] Caves, D, K. Eakin, and A. Faruqui, April 2000. *Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets.* Electricity Journal, Volume 13 Number 3.

[17] Caves, D., K. Eakin, and A. Faruqui, April 2000. *Mitigating Price Spikes in Wholesale Markets*. Electricity Journal Volume13, Number 3.

[18] BPA program brochures and conversation with BPA program manager, John Hairston, October 2000.

[19] Portland General Electric Schedule 86 tariff.

[20] "Power Crunch Prompts IOUs to File Demand Exchange Tariffs," Clearing Up 12/18/2000

[21] Presentation by PSE Vice President P. Gullekson, "Home Comfort Control Pilot and Integrated Technologies." Summer Reliability and Load Management Workshop, Sacramento, CA. October 2000.

[22] See http://www.wisconsinelectric.com.

[23] Reed, John, W. Mok, D. Sumi, and T. Boertman, *Temperature Changes in Residential Dwellings from Direct Control Actions*, American Council for an Energy Efficient Economy 1996 Summer Proceedings.

[24] California Energy Markets November 17, 2000.

[25] November 2000, conversations with staff at Wisconsin Electric: Tim Craft and Don Johnston.

[26] November 2000, conversations with Paul Peterson at New England Independent System Operator.

[27] Cowart, Richard, and N. Reynolds, *The Contribution of Energy Efficiency to the Reliability of the U.S. Electric System,* American Council for an Energy Efficient Economy 2000 Summer Proceedings.

[12] Analysis by the Regulatory Assistance Project. See http://www.rapmaine.org

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[16] Caves, D, K. Eakin, and A. Faruqui, April 2000. *Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets.* Electricity Journal, Volume 13 Number 3.

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[27] Cowart, Richard, and N. Reynolds, *The Contribution of Energy Efficiency to the Reliability of the U.S. Electric System,* American Council for an Energy Efficient Economy 2000 Summer Proceedings.

CHAPTER 1 ELECTRICITY

Section E

Meeting New Electricity Needs

Electricity demand in Washington State has been growing at slightly less than 1% annually. Over the next few years, most new demand is likely to be met by three major sources: combined-cycle combustion turbines fueled by natural gas, wind turbines, and energy efficiency measures. Table 2 provides basic cost information on these three technologies as well as others that are likely to see some development over the next several years. The values in Table 2 are estimated costs to produce a kWh of electricity and do not indicate what price a kWh may sell for in the open market.

Although Washington State has not seen the addition of any large new generating facilities (250 MW or more) during the 1990s, there have been a significant number of small and medium-size new plants added in the last decade as well as upgrades and refurbishments of existing hydroelectric and nuclear facilities. Tables 3 and 4 summarize these capacity additions, upgrades, and refurbishments.

Technology	Range of Costs Cents/kWh			Representative Projects	Notes
	Gas Cost: ($ per MMBtu)				
Natural Gas Technologies	Gas @ $3.50 per MMBtu	Gas @ $4.50 per MMBtu	Gas @ $5.50 per MMBtu		
Combined Cycle Combustion Turbine	3.5¢/kWh	4.3¢/kWh	5.0¢/kWh	♦ Chehalis (Tractabel) ♦ Sumas (NESCO)	Source: Sumas Energy 2 Application
Simple Cycle (Peaking) Turbine	5.1¢/kWh	6.3¢/kWh	7.5¢/kWh		Source: NWPPC, 4th Power Plan
Renewable Technologies	Low Estimate	High Estimate			
Wind	3.2¢/kWh	6.5¢/kWh		♦ Stateline (FPL) ♦ Vansycle	Note: Includes 1.7¢/kWh Federal Production Tax Credit
Biomass	2.4¢/kWh	6.3¢/kWh			Source: NWPPC, 4th Power Plan
Solar	23.0¢/kWh	37.5¢/kWh			Source: Western SUN
Geothermal	5.7¢/kWh (Fourmile Hill)	10.4¢/kWh (NWPPC)		♦ Fourmile Hill (BPA/Calpine)	Sources: BPA Press Release, NWPPC 4th Power Plan
Energy Efficiency	0.4¢/kWh	3.0¢/kWh			Source: NWPPC, 4th Power Plan

Table 2 Electricity Supply Options

♦ 2000 average wholesale natural gas price (Sumas hub): $4.93 per MMBtu 2000 average wholesale electricity price (Mid-Columbia hub): 8.8¢/kWh

Project	Technology	Fuel	Installed Capacity (MW)	Peak Capacity (MW)	Average Energy (MWa)	Capital Cost ($Millions)	Completion Date	County
DoubleTree Hotel Fuel Cell	Fuel Cell	Natural Gas	0.2	0.2				Spokane
Spring Creek	Hydroelectric		0		0		Feb-91	Klickitat
Steam Plant No. 2	Steam	Coal/Wood/Refuse		38	32.3		Mar-91	Pierce
Spokane MSW	Steam	Municipal Solid Waste		23	15.3		Mar-91	Spokane
March Point 1	Combined Cycle (Co-Gen)	Refinery/Natural Gas	80		70		Oct-91	Skagit
March Point 2	Combined Cycle (Co-Gen)	Refinery/Natural Gas	60		52.9		Jan-93	Skagit
Sumas Energy	Combined Cycle (Co-Gen)	Natural Gas		125	97		Apr-93	Whatcom
Encogen 1-3	Combined Cycle (Co-Gen)	Natural Gas		160	140.8		Jul-93	Whatcom
Wynoochee	Hydroelectric		10.8	10.8	4.3		Dec-93	Grays Harbor
Tenaska Washington II	Combined Cycle (Co-Gen)	Natural Gas		245	215.6		Apr-94	Whatcom
Black Creek	Hydroelectric		3.7	2	1.6	7.8	May-94	King
Cowlitz Falls	Hydroelectric		70	44	29.2	103.0	Aug-94	Lewis
Longview Fibre-CT	Combustion Turbine (Co-Gen)	Natural Gas	65				Jun-95	Cowlitz
South Fork Tolt River	Hydroelectric		15	15	8.1	28	Nov-95	King
Fort James (Camas)	Boiler/Turbine (Co-Gen)	Various	52	47	40	53	Dec-95	Clark
Kimberly-Clarke	Boiler/Turbine (Co-Gen)	Various	43		37.1	115	Jan-96	Snohomish
Burton Creek	Hydroelectric		0.8		0.4		May-96	Lewis
Avista Corp. Fuel Cell	Fuel Cell	Natural Gas	0.2				Jun-97	Spokane
River Road Generating Project	Combined Cycle	Natural Gas	248		220	127	Dec-97	Clark
North Side	Internal Combustion	Landfill Gas	0.9			1.3	Jun-98	Spokane
Tacoma Landfill	Internal Combustion	Landfill Gas	1.9	1.9	1.8	2.7	Sep-98	Pierce
Roosevelt Landfill	Internal Combustion	Landfill Gas	8.4		8	12.9	May-99	Klickitat
Total			659.9	711.9	974.4	450.7		

Table 3 New Power Plant Additions (1990's)

Source: Northwest Power Planning Council, Database maintained by Jeff King, July 2000.

Project	Technology	Installed Capacity (MW)	Peak Capacity (MW)	Average Energy (MWa)	Capital Cost ($ Millions)	Completion Date	County
Monroe Street Rehabilitation	Hydroelectric	10		7.6		Jul-92	Spokane
WNP-2 Upgrade 1 (Turbine Rotor)	Nuclear		24	16		Jan-93	Benton
Cushman 1 Runner Replacement	Hydroelectric		0	0.4		Sep-93	Mason
Wanapum Rewinds	Hydroelectric			31.3		Dec-93	Grant
LaGrande Runner Replacement	Hydroelectric	0		0.4		Jun-94	Pierce
Nine Mile 3 & 4 Rehabilitation	Hydroelectric	14		13.4	20	Jul-94	Spokane
WNP-2 Upgrade 2	Nuclear		52	36	25	Jun-95	Benton
SCL Energy Management System	Hydroelectric	0		15	22.8	Nov-95	King
Diablo Runner Replacement	Hydroelectric	10		8		Dec-95	Whatcom
George Runner Replacement	Hydroelectric	0		1		Dec-95	Whatcom
Long Lake 1,2,4 Turbine Replacement	Hydroelectric	12		1.2		Sep-96	Lincoln
Cushman 2 Runner Replacement	Hydroelectric		0	0.9		Oct-96	Mason
Cedar Falls Rewind	Hydroelectric	0		0.6		Dec-96	King
McNary Dam Fish Attraction	Hydroelectric	9.9		8	32.7	Nov-97	Benton
Grand Coulee 22-24 Stator Replacement	Hydroelectric	315	315		30	Dec-97	Grant
Ross Runner Replacement	Hydroelectric	0	2.2	2.1		Dec-97	Whatcom
Long Lake 3 Turbine Replacement	Hydroelectric	4	393.2	0.3	1	Dec-00	Lincoln
Total		374.9	786.4	135	131.5		

Table 4 Hydroelectric and Nuclear Refurbishment/Expansion (1990's)

Source: Northwest Power Planning Council, Database maintained by Jeff King, July 2000.